#### **Class VI UIC Area of Review and Corrective Action**

This submission is for:

Project ID: R09-CA-0010

Project Name: Mullen Storage Project

Current Project Phase: Pre-Injection Prior to Construction

#### Overview

Simulator Used for AoR delineation modeling: GEM

Version Used: GEM 2019.10

 $Simulator \ Description/Documentation: \ \underline{https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no.\ wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-precipition/Documentation: \ \underline{https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no.\ wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-precipition/Documentation/AoRModeling-05-precipition/AoRModel$ 

03-2022-1838/CMG GEM Simulator--Documentation.pdf

Total Simulation Time From Start of Injection: 128 yrs

Additional AoR Delineation Information: <a href="https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-thtps://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-thtps://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-thtps://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-thtps://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-thtps://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-thtps://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-thtps://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-thtps://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-thtps://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-thtps://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-thtps://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submission/AoRModeling-thtps://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submission/AoRModeling-thtps://gsdt.pnnl.gov/alfresco/getFile/no\_wiki/shared/Submission/AoRModeling-thtps://gsdt.pnnl.gov/alfresco/getFile/no\_wiki/shared/Submission/AoRModeling-thtps://gsdt.pnnl.gov/alfresco/getFile/no\_wiki/shared/Submission/AoRModeling-thtps://gsdt.pnnl.gov/alfresco/getFile/no\_wiki/shared/Submission/AoRModeling-thtps://gsdt.pnnl.gov/alfresco/getFile/no\_wiki/shared/Submission/AoRModeling-thtps://gsdt.pnnl.gov/alfresco/getFile/no\_wiki

05-03-2022-1838/CTV--III-----AoR\_CA--AoR--Delineation.pdf

#### **Model Domain**

Coordinate System: State Plane

Horizontal Datum: NAD27

Coordinate System Units: ft

Vertical Datum: Mean Sea Level

Describe Vertical Datum: Mean Sea Level

Zone: 2

FIPSZONE: 402 ADSZONE: 3301

Mesh Type: Other

Describe Mesh Type: Tartan

Domain Size in Global Units Specified Above

Domain Coordinates File: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-03-2022-

1838/CTV--III-----Confidentiality-----Domain--Coord.pdf

Grid Size

Number of Nodes in x: 125 y: 125 z: 133

Grid Spacing: Variable

Grid File Format: ASCII file containing vertices and elements

Grid File Description: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-03-2022-

 $\underline{1838/CTV\text{--}III\text{----}AoR\_CA\text{--}Grid\text{--}File\text{--}Description.pdf}}$ 

Grid Data File: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-03-2022-1838/CTV-

-III-----Grid.pdf

Faults Modeled: No Caprock Modeled: No

 $Image\ File(s)\ for\ Model\ Domain\ Grid:\ \underline{https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-preconstru$ 

03-2022-1838/CTV--III-----Confidentiality-----Grid--image.pdf

## **Processes Modeled by Simulator**

Reservoir Conditions:

Supercritical CO2 Conditions

Phases Modeled:

Aqueous Supercritical CO2

Aqueous Phase:

Phase Compressibility: Compressible

Compressibility Value: 0.000003 1/psi

Phase Composition: Compositional

Aqueous Phase Components:

CO<sub>2</sub> Water

Supercritical CO2 Phase:

Phase Compressibility: Compressible
Phase Composition: Compositional
Supercritical CO2 Phase Components:

CO<sub>2</sub>

Equation of State Description Including Reference: CMG GEM uses Peng Robinson EOS

File with EOS Reference or Documentation: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-

PreConstruction/AoRModeling-05-03-2022-1838/EOS--SPE-89343 Reservoir-Simulation-of-CO2-Storage-in-Deep-Saline-Aquifers.pdf

Multifluid Flow Processes:

Advection Dispersion Diffusion Buoyancy

Non-wetting Fluid Trapping Pore Compressibility

Thermal Conditions: Isothermal Heat Transport Processes:

Geochemistry Modeled: No

Geomechanical/Structural Deformations Modeled: No

## **Rock Properties and Constitutive Relationships**

Porosity/Permeability Model

Single Porosity

Porosity Distribution: Heterogeneous

2022-1838/CTV--III-----Confidentiality-----Porosity.pdf

File Describing how Porosity was Determined and Assigned to Numerical Model: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-

0010/Phase1-PreConstruction/AoRModeling-05-03-2022-1838/CTV--III-----AoR CA--Porosity--determination.pdf

Image Files for Porosity Distributions: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-

PreConstruction/AoRModeling-05-03-2022-1838/CTV--III-----AoR CA--Porosity--distribution.pdf

Permeability Distribution: Heterogeneous

Spatially Variable Permeability File: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-

05-03-2022-1838/CTV--III-----Confidentiality-----Permeability.pdf mD

File Describing how Permeability was Determined and Assigned to Numerical Model: <a href="https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-">https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-</a>

CA-0010/Phase1-PreConstruction/AoRModeling-05-03-2022-1838/CTV--III-----AoR CA--Permeability--determination.pdf

Image Files for Permeability Distributions: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-

PreConstruction/AoRModeling-05-03-2022-1838/CTV--III-----AoR CA--Permeability--distribution.pdf

Number of Rock Types Modeled: 1

Description of Rock Type Selection and Assignment: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-

PreConstruction/AoRModeling-05-03-2022-1838/CTV--III-----AoR CA--Rock--type--determination.pdf

Rock Type Distribution Data File: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-

05-03-2022-1838/CTV--III-----Confidentiality-----Rock--type.pdf

Image Files for Rock Type Distribution: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-

PreConstruction/AoRModeling-05-03-2022-1838/CTV--III-----AoR\_CA--Rock--type--distribution.pdf

#### Rock Type #1

Rock Compressibility: Pore

Rock Compressibility Distribution: Single Value
Compressibility Value: 0.000003 1/psi

Constitutive Relationships

Aqueous Saturation vs. Capillary Pressure: Functional Form

File Describing Functional Form Used for Aqueous Saturation vs Capillary Pressure:

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-03-2022-1838/CTV-III-----AoR\_CA-Capillary--Pressure.pdf

Aqueous Trapped Gas Modeled: Yes

Hysteresis other than non-wetting fluid trapping: No

Aqueous Relative Permeability: Functional Form

File Describing Functional Form Used for Aqueous Relative Permeability: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-

#### 0010/Phase1-PreConstruction/AoRModeling-05-03-2022-1838/CTV--III-----AoR\_CA--Relative--permeability-----Water.pdf

Hysteresis other than non-wetting fluid trapping: No

Gas Relative Permeability: Functional Form

File Describing Functional Form Used for Gas Relative Permeability: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-

0010/Phase1-PreConstruction/AoRModeling-05-03-2022-1838/CTV--III-----AoR\_CA--Relative--permeability-----Gas.pdf

Hysteresis other than non-wetting fluid trapping: No

Porosity and Permeability Reduction Due to Salt Precipitation

## **Boundary Conditions**

Attach Boundary Conditions Description File: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-

PreConstruction/AoRModeling-05-03-2022-1838/CTV--III-----AoR CA--Boundary--conditions.pdf

#### **Initial Conditions**

Initial Phases in Domain: Aqueous

Initial Aqueous Pressure: Varying with Depth, Temperature, and Salinity
Initial Aqueous Pressure: 2860 psi at Reference Elevation: 6900 ft

Initial Temperature: Varying with Depth

Initial Temperature: 151 F at Reference Elevation: 6900 ft Gradient: 0.013 deg F/ft

Initial Salinity: Spatially Constant Initial Salinity: 15500 ppm

#### **Operational Information**

Number of Injection Wells: 6

Injection Well #1

Well Direction: Vertical

Location: X: 0 Model Units Y: 0 Model Units

Wellbore Diameter: Variable

#### 03-2022-1838/CTV--III-----Injector--C1-----Wellbore--Dia.pdf

Well Screen Interval Provided as: Single Interval

Elevation of Top of Screened Interval: 0 Elevation of Bottom of Screened Interval: 0 ft

Mass Rate of Injection: 1 MMT/yr
Total Mass of Injection: 28.2 MMT
Fracture Gradient: 0.76, psi/ft

Maximum Injection Pressure: 4224 psi Elevation Corresponding to Pressure: 6178 ft

Description of How Fracture Gradient and Maximum Injection Pressure were Determined File:

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-03-2022-1838/CTV--III-----Injector--C1-

### ----Frac--gradient.pdf

Composition of Injectate: Pure CO2

Injection Schedule Provided as: Single Injection Period

Injection Start Date: 01/01/2026 Stop Date: 01/01/2054

#### Injection Well #2

Well Direction: Vertical

Location: X: 0 Model Units Y: 0 Model Units

Wellbore Diameter: Variable

Wellbore Diameter File: https://qsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-

#### 03-2022-1838/CTV--III-----Injector--C2-----Wellbore--Dia.pdf

Well Screen Interval Provided as: Single Interval

Elevation of Top of Screened Interval: 0 Elevation of Bottom of Screened Interval: 0 ft

Mass Rate of Injection: 1 MMT/yr Total Mass of Injection: 28.2 MMT Fracture Gradient: 0.76 psi/ft

Maximum Injection Pressure: 4919 psi Elevation Corresponding to Pressure: 7192 ft

Description of How Fracture Gradient and Maximum Injection Pressure were Determined File:

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-03-2022-1838/CTV--III------Injector---C2-

#### ----Frac--gradient.pdf

Composition of Injectate: Pure CO2

Injection Schedule Provided as: Single Injection Period
Injection Start Date: 01/01/2026 Stop Date: 01/01/2054

#### Injection Well #3

Well Direction: Vertical

Location: X: 0 Model Units Y: 0 Model Units

Wellbore Diameter: Variable

Wellbore Diameter File: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-

#### 03-2022-1838/CTV--III-----Injector--E1-----Wellbore--Dia.pdf

Well Screen Interval Provided as: Single Interval

Elevation of Top of Screened Interval: 0 Elevation of Bottom of Screened Interval: 0 ft

Mass Rate of Injection: 0.25 MMT/yr
Total Mass of Injection: 2.5 MMT
Fracture Gradient: 0.76 psi/ft

Maximum Injection Pressure: 4111 psi Elevation Corresponding to Pressure: 6011 ft

Description of How Fracture Gradient and Maximum Injection Pressure were Determined File:

#### ----Frac--gradient.pdf

Composition of Injectate: Pure CO2

Injection Schedule Provided as: Single Injection Period
Injection Start Date: 01/01/2026 Stop Date: 01/01/2036

#### Injection Well #4

Well Direction: Vertical

Location: X: 0 Model Units Y: 0 Model Units

Wellbore Diameter: Variable

## 03-2022-1838/CTV--III-----Injector--E2-----Wellbore--Dia.pdf

Well Screen Interval Provided as: Single Interval

Elevation of Top of Screened Interval: 0 Elevation of Bottom of Screened Interval: 0 ft

Mass Rate of Injection: 0.25 MMT/yr
Total Mass of Injection: 3.5 MMT
Fracture Gradient: 0.76 psi/ft

Maximum Injection Pressure: 4774 psi Elevation Corresponding to Pressure: 6984 ft

Description of How Fracture Gradient and Maximum Injection Pressure were Determined File:

#### ----Frac--gradient.pdf

Composition of Injectate: Pure CO2

Injection Schedule Provided as: Single Injection Period
Injection Start Date: 01/01/2026 Stop Date: 01/01/2040

#### Injection Well #5

Well Direction: Vertical

Location: X: 0 Model Units Y: 0 Model Units

Wellbore Diameter: Variable

Wellbore Diameter File: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-precipitation wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-precipitation wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-precipitation wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-precipitation wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-precipitation wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-precipitation wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-precipitation wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-precipitation wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-precipitation wiki/shared/Submissions/R09-CA-0010/Phase1-Precipitation wiki/shared/Submissions/R09-CA-0010

## $\underline{03\text{-}2022\text{-}1838/CTV\text{--}III\text{-----}Injector\text{--}W1\text{-----}Wellbore\text{--}Dia.pdf}$

Well Screen Interval Provided as: Single Interval

Elevation of Top of Screened Interval: 0 Elevation of Bottom of Screened Interval: 0 ft

Mass Rate of Injection: 0.25 MMT/yr Total Mass of Injection: 1.3 MMT Fracture Gradient: 0.76 psi/ft Maximum Injection Pressure: 4207 psi Elevation Corresponding to Pressure: 6155 m

Description of How Fracture Gradient and Maximum Injection Pressure were Determined File:

https://gsdt.pnnl.gov/alfresco/service/velo/qetFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-03-2022-1838/CTV--III------Injector--

#### W1-----Frac--gradient.pdf

Composition of Injectate: Pure CO2

Injection Schedule Provided as: Single Injection Period
Injection Start Date: 01/01/2026 Stop Date: 01/01/2031

#### Injection Well #6

Well Direction: Vertical

Location: X: 0 Model Units Y: 0 Model Units

Wellbore Diameter: Variable

Wellbore Diameter File: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-

## 03-2022-1838/CTV--III-----Injector--W2-----Wellbore--Dia.pdf

Well Screen Interval Provided as: Single Interval

Elevation of Top of Screened Interval: 0 Elevation of Bottom of Screened Interval: 0 ft

Mass Rate of Injection: 0.5 MMT/yr
Total Mass of Injection: 7 MMT
Fracture Gradient: 0.76 psi/ft

Maximum Injection Pressure: 4802 psi Elevation Corresponding to Pressure: 7020 ft

Description of How Fracture Gradient and Maximum Injection Pressure were Determined File:

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-03-2022-1838/CTV--III-----Injector--

#### W2----Frac--gradient.pdf

Composition of Injectate: Pure CO2

Injection Schedule Provided as: Single Injection Period
Injection Start Date: 01/01/2026 Stop Date: 01/01/2042

Number of Production/Withdrawal Wells: 0

## **Model Output/Results**

Provide file name and corresponding spatial location for each file: CBI

Time-Series File: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-03-2022-

1838/CTV--III-----AoR CA--Computational--Modeling--time--series.pdf

Provide file name and corresponding variable and time stamp for each file: CBI

Snapshot File: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-03-2022-1838/CTV-

#### -III-----Confidentiality-----Snapshot.pdf

Provide file name and corresponding description of surface for each file: CBI

Surface Flux File: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/AoRModeling-05-03-2022-

1838/CTV--III-----Confidentiality-----Flux.pdf

### **AoR Pressure Front Delineation**

Lowermost USDW:

Name of Lowermost USDW: Undifferentiated Non-Marine Sediments

Water Density: 999.6 kg/m^3 at Elevation: 2517 ft

Location of Measurement for Density: Regional assessment

Temperature: 94 F at Elevation: 2517 ft

Location of Measurement: Regional assessment

Pressure: 1090 psi at Elevation: 2517 ft

Location of Measurement: Regional assessment

Salinity: 7900 ppm at Elevation: 2517 ft

Location of Measurement: Regional assessment

Elevation of bottom of USDW: 2517 ft

Injection Zone:

Name of Injection Zone: Injection zone

Water Density: 993.8 kg/m^3 at Elevation: 5941 ft

Location of Measurement: Regional assessment

Temperature: 138 F at Elevation: 5941 ft

Location of Measurement: Regional assessment

Pressure: 2444 psi at Elevation: 5941 ft

Location of Measurement: Regional assessment

Salinity: 15500 ppm at Elevation: 5941 ft

Location of Measurement: Regional assessment

Elevation of top of Injection Zone: 5941 ft

Method of Estimating Critical Pressure: Other

File Describing Critical Pressure Estimation: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-

PreConstruction/AoRModeling-05-03-2022-1838/CTV--III-----AoR CA--Critical--Pressure--Calculation.pdf

Estimated Critical Pressure: 2577 psi

Delineated AoR:

PreConstruction/AoRModeling-05-03-2022-1838/CTV--III-----Confidentiality-----AoR--shapefile.pdf

#### **Corrective Action**

Corrective Action Comments: CBI

# Area of Review and Corrective Action Plan [40 CFR 146.82(a)(13) and 146.84(b) or applicable state requirements]

Are you making an Area of Review and Corrective Action Plan submission at this time?: Yes

Reason for Project Plan Submission: Permit application submission

Project Plan Upload

Attach the Area of Review and Corrective Action Plan: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-

PreConstruction/AoRModeling-05-03-2022-1838/Attachment--B-----CTV--III-----AoR CA.pdf

Appendices and Supporting Materials Upload

#### Area of Review Reevaluation [40 CFR 146.84(e) or applicable state requirements]

Minimum fixed frequency of AoR reevaluation: 5 Years

Are you making an Area of Review reevaluation submission at this time?: No

Reevaluation Background

Reevaluation Materials

Please upload your amended AoR and Corrective Action Plan on the previous tab.

## **Complete Submission**

Authorized submission made by: Siraj Moopen

For confirmation a read-only copy of your submission will be emailed to: travis.hurst@crc.com

# ATTACHMENT B: AREA OF REVIEW AND CORRECTIVE ACTION PLAN 40 CFR 146.84(b)

#### **Facility Information**

Facility name: CTV III

Facility contact: William Chessum / Technical Manager

(562) 999-8380 / William.chessum@crc.com

Location:

### 3.0 AoR and Corrective Action Plan

### 3.1 Computational Modeling Approach

The computational modeling workflow begins with the development of a three-dimensional representation of subsurface geology. It leverages well data (bottom and surface hole location, wellbore trajectory, well logs, etc.) and 3-D seismic data for rendering structural surfaces into a geo-cellular grid. Attributes of the grid include porosity and permeability distributions of reservoir lithologies. This geologic model is often referred to as a static model, as it reflects the reservoir at a single moment. CTV licenses Schlumberger Petrel, industry-standard geo-cellular modeling software, for building and maintaining static models. The static model becomes dynamic in the computational modeler with the addition of:

- Fluid properties such as density and viscosity for CO<sub>2</sub> and water phases
- Liquid and gas relative permeability
- Capillary pressure data
- Proposed injection well completions and injection rates over the life of the project

Results from the computational model are used to establish the area of review (AoR), the 'region surrounding the geologic sequestration project where underground sources of drinking water (USDWs) may be endangered by the injection activity' (EPA 75 FR 77230). In the case of the CTV III storage project, the AoR encompasses the maximum aerial extent of the critical pressure front that was calculated as being necessary to move brine from the injection zone to the USDW via an open conduit.

### 3.1.1 Model Background

Computational modeling was completed using Computer Modeling Group's (CMG) Equation of State Compositional Simulator (GEM). GEM is capable of modeling enhanced oil recovery, chemical EOR, geomechanics, unconventional reservoir, geochemical EOR and carbon capture and storage. GEM can model flow of three components (gas, oil and aqueous) and multi-phase fluids as well as predict phase equilibrium compositions, densities, and viscosities of each phase. This simulator incorporates all the physics associated with handling of relative permeability as a function of interfacial tension (IFT), velocity, composition, and hysteresis. Computational modeling for the CO<sub>2</sub> plume utilized the Peng-Robinson Equation of State and the solubility of CO<sub>2</sub> in water is modeled by Henry's Law. The Peng-Robinson Equation of State establishes the properties of CO<sub>2</sub> over the Pressures and temperatures of the model. Solubility of CO<sub>2</sub> in aqueous phase was modeled by Henry's Law as a function of pressure, temperature, and salinity.

The plume model defines the potential quantity of  $CO_2$  stored and simulates lateral and vertical movement of the  $CO_2$  to define the extent of the  $CO_2$  plume and the pressure changes in the reservoir during and after injection which are used to define the AoR.

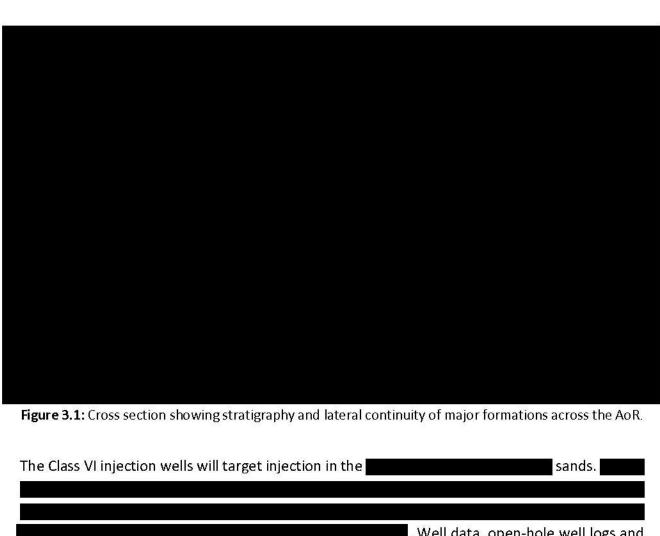
The simulator predicts the evolution of the CO2 plume by:

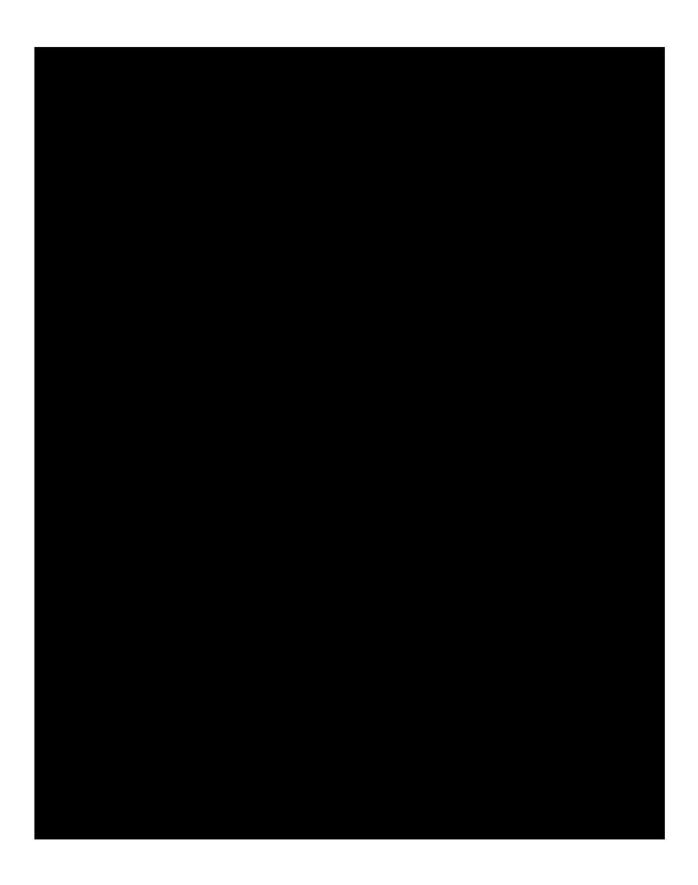
- Incorporating complex reservoir geometry and wells and utilizing a full field static geological three-dimensional characterization of the reservoir incorporating lithology, saturation, porosity, and permeability.
- 2. Forecasting the CO<sub>2</sub> plume movement and growth by inputting the operating parameters into simulation (injection pressure and rates).
- 3. Assessing the movement of CO<sub>2</sub> after injection ceases and allowing the plume to reach equilibrium, including pressure equilibrium and compositions in each phase.

CMG's GEM software has been used in numerous CO<sub>2</sub> sequestration peer reviewed papers, including:

- 1. Simulation of CO<sub>2</sub> EOR and Sequestration Processes with a Geochemical EOS Compositional Simulator. L. Nghiem et al
- 2. Model Predictions Via History Matching of CO<sub>2</sub> Plume Migration at the Sleipner Project, Norwegian North Sea. Zhang, Guanru et al
- 3. Geomechanical Risk Mitigation for CO<sub>2</sub> Sequestration in Saline Aquifers. Tran, Davis et al.

3.1.2 Site Geolo	gy and Hydrolog	gy		
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#### 3.1.3 Model Domain

A static geological model developed with Schlumberger's Petrel software, commonly used in the petroleum industry for exploration and production, is the computational modeling input. It allows the user to incorporate seismic and well data to build reservoir models and visualize reservoir simulation results. Model domain information is summarized in **Table 3.1**.

Table 3.1. Model domain information.

Coordinate System	State Plane			
HorizontalDatum	North American Datum (NAD) 27			
Coordinate System Units	Feet			
Zone	Zone 2			
FIPSZONE	0402	ADSZONE	3301	
Coordinate of X min		Coordinate of X max		
Coordinate of Y min		Coordinate of Y max		
Elevation of bottom of domain		Elevation of top of domain		

A tartan grid with varying cell XY dimensi	ions was rotated
	aligned with the structural
and depositional trends of the	and is parallel to the direction of fluid
predominantly 500'x500' but some cells a	on times. In the $CO_2$ plume area, the grid cells are re as small as $50'x50'$ in the region immediately around increases with greater distance away from the main
STREET	00' cover the areas of the model that are furthest from



The open-hole logs have a half-foot resolution and a constant vertical cell height of 20 feet was utilized over the model domain to generate grid layers as shown in **Figure 3.4**. The 20-foot cell height provides the vertical resolution necessary to capture significant lithologic heterogeneity (sand versus shale) which helps to ensure accurate upscaling of log data and distribution of reservoir properties in the static model. **Figure 3.5** shows a comparison of open-hole log data and the associated upscaled logs for a well within the AoR.





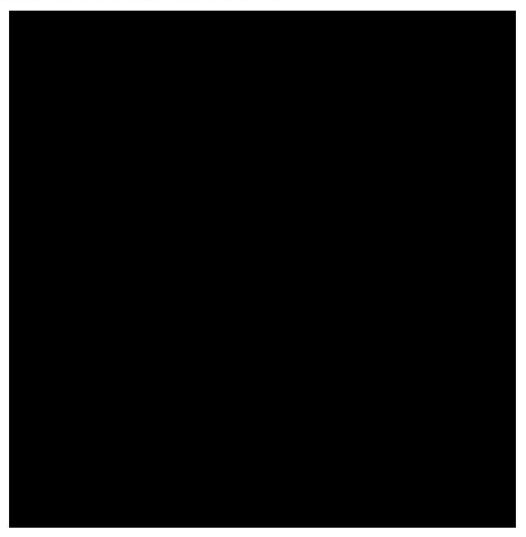
### 3.1.4 Porosity and Permeability

Wireline log data was acquired with measurements that include but are not limited to spontaneous potential, natural gamma ray, borehole caliper, compressional sonic, resistivity as well as neutron porosity and bulk density.

Formation porosity is determined one of two ways: from bulk density using 2.65 g/cc matrix density as calibrated from core grain density and core porosity data, or from compressional sonic using 55.5 µsec/ft matrix slowness and the Raymer-Hunt equation.

Volume of clay is determined by spontaneous potential and is calibrated to core data.

Log-derived permeability is determined by applying a core-based transform that utilizes capillary pressure porosity and permeability along with clay values from XRD or FTIR. Core data from two wells with 13 data points was used to develop a permeability transform (Figure 3.6). The transform from core data is illustrated in Figure 3.7.



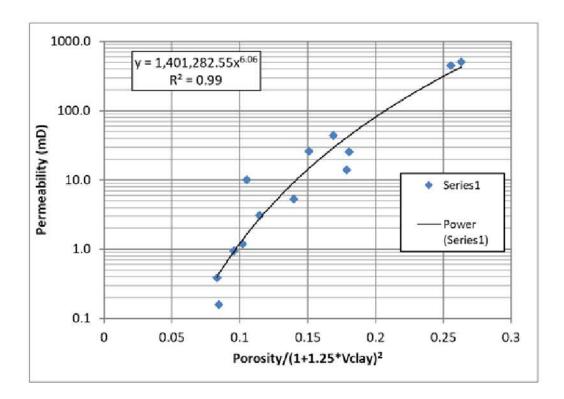


Figure 3.7. Permeability transform for Sacramento Basin zones

Figure 3.8 shows porosity and permeability histograms for Porosity is derived from open-hole well log analysis and permeability is a function of porosity and clay volume. Figure 3.8 shows the distribution of permeability and porosity using Sequential Gaussian simulation (kriging) within the static model.

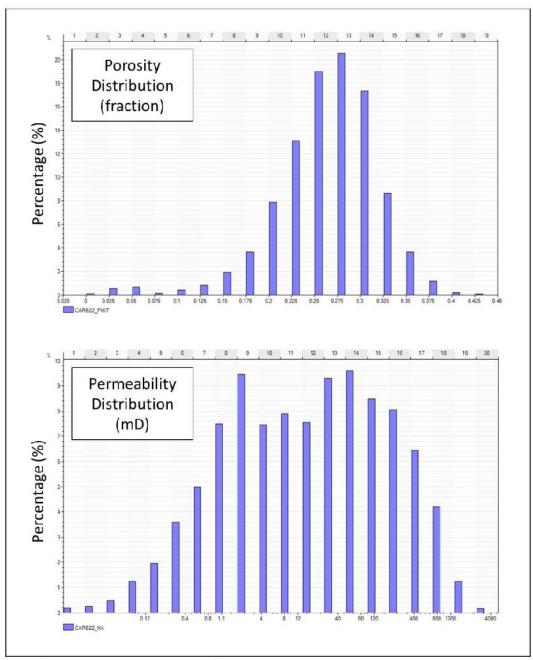
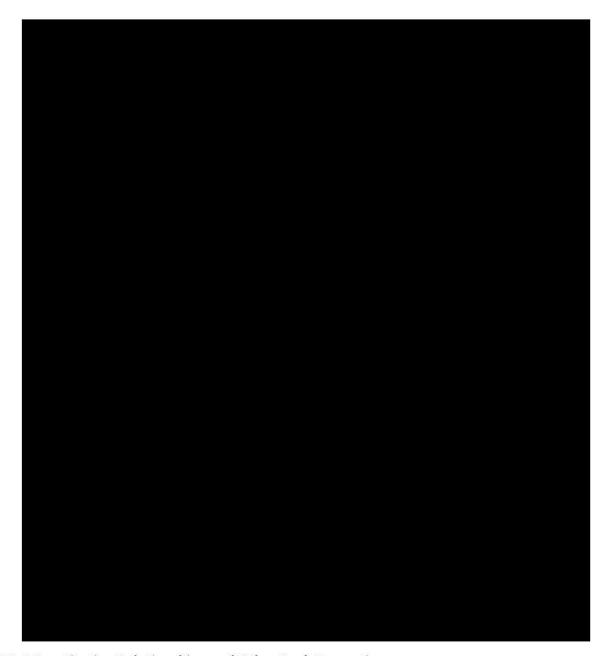
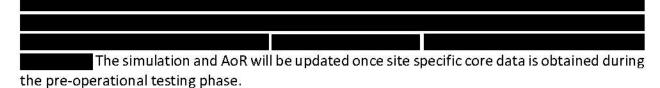


Figure 3.8. porosity and permeability distribution in the static model.



## 3.1.5 Constitutive Relationships and Other Rock Properties



**Figure 3.10 and 3.11** shows the relative permeability curve and capillary pressure curve used in the computational modeling.

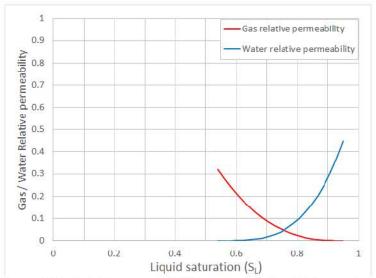


Figure 3.10. Relative permeability curves for Gas-Water system

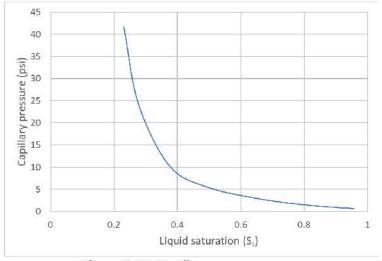


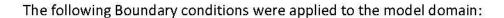
Figure 3.11. Capillary pressure curve

#### 3.1.6 Mineralization

Previous studies into reactive transport modeling and geochemical reaction in CCS have shown that the amount of CO<sub>2</sub> trapped by mineralization reactions is extremely small over a 100-year post injection time frame (IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage, prepared by Working Group III of the Intergovernmental Panel on Climate Change) for sandstone reservoirs.

Due to the low salinity expected for the formation, minor expected effect on the AoR and for computational efficiency, reactive transport was not included as a part of the compositional simulation modeling done for the project at this time.

## 3.1.7 Boundary Conditions



shale which is continuous and present at thickness >100' over the model domain has low permeability, has been shown to be a proven hydrocarbon seal over the model domain and was thus set as a no flow boundary.



## 3.1.8 Initial Conditions

Initial model conditions (start of CO<sub>2</sub> injection) of **Table 3.2**.

Table 3.2. Initial conditions.

Parameter	Value or Range	Units	Corresponding Elevation (ft MSL)	Data Source
Temperature	151	Fahrenheit		Bottom hole temperature data from logs in the area
Formation pressure	2860	Pounds per square inch		
Salinity	15,500	Parts per million	,at	Water analysis and Log calculated salinity curves

## 3.1.9 Operational Information

Narrative document and in the Operational Procedures Appendix.
2.1.10 Eracture Drossure and Eracture Gradient

#### Sizilo i lactare i ressare ana i ractare Gradient

Calculated fracture gradient and target injection pressure values are given in Table 3.4.

A fracture pressure gradient of 0.76 psi/ft is assumed for the injection zone.

CTV will conduct a step rate test in the injection zone as part of the pre-operational testing plan to confirm this fracture pressure gradient.

At this time, no fracture gradient information has been found for \_\_\_\_\_\_\_. CTV will conduct a step rate test for \_\_\_\_\_\_ as part of the pre-operational testing.

CTV will ensure that the injection pressure is below 90% of the injection zone fracture gradient at the top of perforations in the injection wells (Table 3.4). CTV expects to operate the wells with a planned bottom hole injection pressure well below the maximum allowable injection pressure calculated using the fracture gradient and safety factor.

**Table 3.4.** Injection pressure details.

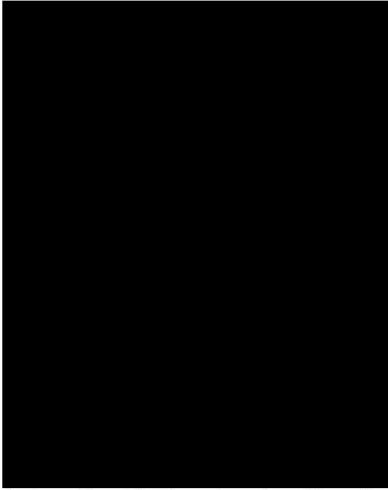
Injection Pressure Details	Injection Well C1	Injection Well C2	Injection Well E1	Injection Well E2	Injection Well W1	Injection Well W2
Fracture gradient (psi/ft)	0.76	0.76	0.76	0.76	0.76	0.76
Maximum allowable injection pressure (90% of fracture pressure) (psi)	4224	4919	4111	4774	4207	4802
Elevation corresponding to maximum injection pressure (ft TVD)	6178	7192	6011	6984	6155	7020
Elevation at the top of the perforated interval (ft TVD)	6178	7192	6011	6984	6155	7020
Calculated maximum injection pressure at the top of the perforated interval (psi)	4224	4919	4111	4774	4207	4802
Planned injection pressure (psi) / gradient (psi/ft) at top of perforations	3050 / 0.494	3566 / 0.496	2901 / 0.483	3363 / 0.482	2961 / 0.481	3504 / 0.499

### 3.2 Computational Modeling Results

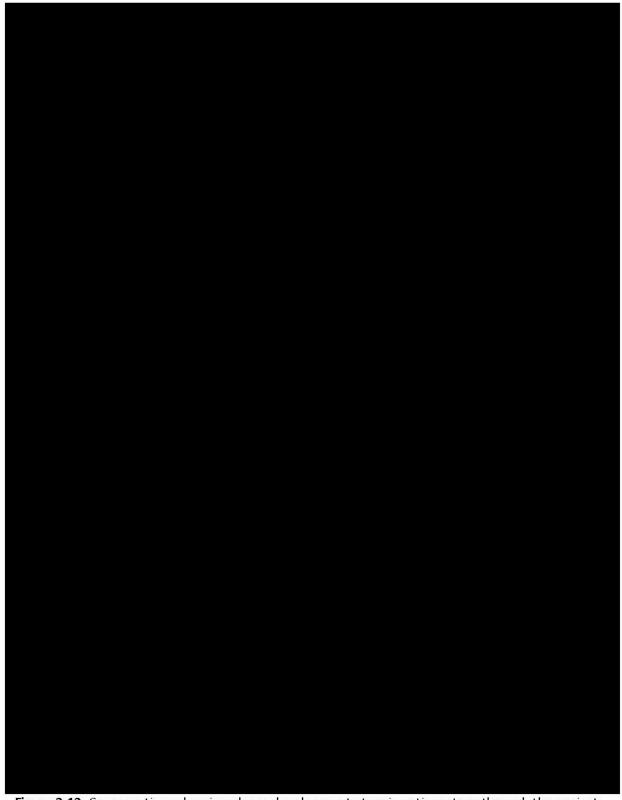
## 3.2.1 Predictions of System Behavior

**Figure 3.12** and **Figure 3.13** show the computational modeling results and development of the  $CO_2$  plume at different time steps. The boundaries of the  $CO_2$  plume have been defined with a 0.01  $CO_2$  global mole fraction cutoff.

As shown in **Figure 3.12**, the  $CO_2$  extent is largely defined by Year 52 after the end of injection. The majority of the  $CO_2$  injectate remains as super-critical  $CO_2$  (83%) with the remaining portion of the  $CO_2$  dissolving in the formation brine over the simulated 100 years post injection.



**Figure 3.12:** Plume development through time: 1-year, 4-year, 6-year, 10-year, 16-year, 28-year (end of injection), 52-year post injection and 100-year post injection.



**Figure 3.13.** Cross-sections showing plume development at various time steps through the project.



**Figure 3.14.** CO<sub>2</sub> storage mechanisms in the reservoir.

#### 3.2.2 Model Calibration and Validation



In addition, scenarios were run to test the effect of varying major model inputs on the  $CO_2$  plume and AoR extent.

**Table 3.5.** Simulation sensitivity scenarios

Scenario	CO <sub>2</sub> plume & AoR impact
Porosity: 10% reduction from base case	Minimal Impact
Porosity: 10% increase from base case	Minimal Impact
Permeability: 10% reduction from base case	Minimal Impact
Permeability: 10% increase from base case	Minimal Impact

These scenarios and the comparison against previous work in the area provides us with confidence in the  $CO_2$  plume extent and AoR, and that the corrective action well review and potential impact to the USDW has been appropriately evaluated.

## 3.2.3 AoR Delineation

	on was based on the methods of Norrective Action Guidance.	licol et al. (2008), which is referenced in the
OS EL A AOIT and El	orrective Action database.	
	iguno 2 15	proceure profile and date
r	igure 3.15.	pressure profile and data

For the purpose of calculating the critical pressure and delineating the AoR for the project area, and the following equations were used to calculate critical pressure across the model domain:

$$\Delta P_{C,norm} = g(Z_V - Z_I) \left[ \frac{\lambda - \xi}{2} (Z_V - Z_I) + \rho_{I,\lambda} - \rho_I \right] - \text{Eq (1)}$$

$$\Delta P_c = \Delta P_{C,norm} + \Delta P_u$$
 – Eq (2)

Where,

 $\Delta P_{C,norm}$  - the admissible overpressure in a normally pressured aquifer before fluid in the injection zone would flow into the USDW through a hypothetical open conduit

 $\Delta P_c$  - the admissible overpressure in an under-pressured aquifer before fluid in the injection zone would flow into the USDW through a hypothetical open conduit

 $\Delta P_u$  - the difference of normal pressure to actual pressure in the under-pressured aquifer, assumed psi across the model domain

g - acceleration due to gravity, 9.81m/s<sup>2</sup>

 $Z_V$  - Elevation of the injection zone

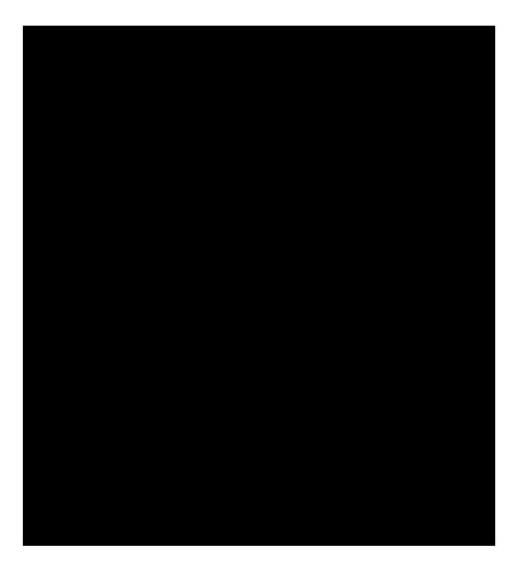
 $Z_I$  - Elevation of the base of the USDW

density gradient in the conduit at constant injection zone brine TDS

 $\xi$  - density gradient in the conduit at initial condition  $\rho_{I,\lambda}$  - Density of the injection zone brine at USDW depth

 $ho_{l}$  - Density of the brine in the conduit at USDW depth at initial condition

An average TDS of 15,500ppm was assumed for the injection zone and an average TDS of 7,900ppm was assumed for the USDW based on Salinity calculations in the project area. Injection zone and USDW depths were based on the model grid and USDW mapping in the project area. Density and density gradients were calculated as a function of temperature and salinity using standard methods (McCutcheon et. al. 1993). Using these, the critical pressure was calculated at each grid point in the Petrel model using **Equations 1 & 2**, and combined with the pressure outputs from the plume simulation to delineate an AoR boundary at different timesteps. The final AoR boundary was based on the outermost threshold overpressure 14 years into the injection which is when the maximum extent was seen. **Figure 3.17** shows the AoR extent, CO<sub>2</sub> plume extent, injector locations and proposed monitoring well locations. Details on the monitoring wells are discussed in further detail in Attachment C – Testing and Monitoring Plan.



## 3.3 Corrective Action

#### 3.3.1 Tabulation of Wells within the AoR

. As such, there are excellent records for wells drilled in the study area. There have been no undocumented historical wells found in the AoR.

CTV accessed internal databases as well as California Geologic Energy Management Division (CalGEM) information to identify and confirm wells within the AoR.

Table 3.8 provides counts of the AoR wellbores by status and type, for each wellbore with a unique API-12 identifier. Appendix B-1 provides a complete list of all wellbores by API-12 within the AoR. As required by 40 CFR 146.84(c)(2), the well table in Appendix B-1 describes each well's type, construction, date drilled, location, measured depth, true vertical depth, completion record relative to

corrective action, if necessary. CTV also identifies well work to be completed during the preoperational testing phase.

Table 3.8: Wellbores in the AoR by Status

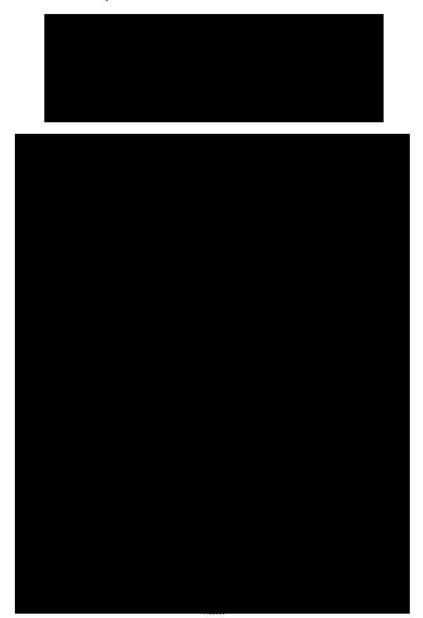


Figure 3.18. Wells penetrating the reviewed for corrective action. Wells requiring corrective action prior to injection are identified by magenta circles.

### 3.3.2 Protection of USDW

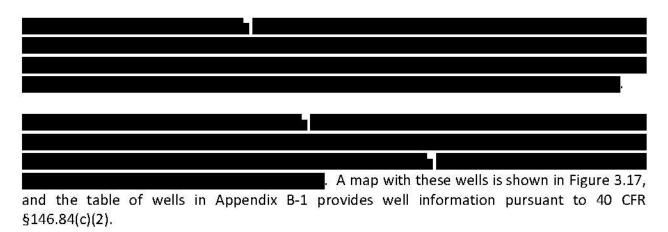
## 3.3.3 Wells Penetrating the Confining Zone

The depth of the confining zone in each of the wells penetrating was determined by interpretation of open-hole well logs and utilizing the deviation survey. All wells in the AoR penetrate zone. These wells also penetrate storage reservoir.

## 3.3.4 Isolation

If isolation of this formation is determined to be deficient in such a way that USDW may be impacted, corrective action plans will be communicated and implemented prior to injection to ensure non-endangerment of USDW.

## 3.3.5 Corrective Action Assessment of Wells in AoR



## 3.3.6 Plan for Site Access

CTV has obtained surface access rights for the duration of the project.

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will ensure that CO<sub>2</sub> is confined to the injection zone within the AoR, protecting the overlying USDW and ensuring confinement.

Through time, if the plume development is not consistent with the predicted results, computational modeling will be updated to reassess the AoR. In this event, all wells in the updated AoR will be subject to the Corrective Action Plan and be remediated if necessary.

#### 3.4 Reevaluation Schedule and Criteria

## 3.4.1 AoR Reevaluation Cycle

CTV will reevaluate the above described AoR at a minimum every five years during the injection and post-injection phases, as required by 40 CFR 146.84 (e).

Simulation study results are reviewed when operating data is acquired. Preparation of necessary operational data for the review includes injection rates and pressures, CO<sub>2</sub> injectate concentrations, and monitoring well information (storage reservoir and overlying dissipation intervals).

Dynamic operating and monitoring data that will be incorporated into future reevaluation will include:

- 1. Pressure data from monitoring wells that constrain and define plume development.
- CO2 content/saturation from monitoring wells. This data may be acquired with direct aqueous measurements and cased hole log results that will constrain and define plume development.
- 3. Injection pressures and volumes. The injection pressures and volumes in the computational model are maximum values. If the actual rates are lower than expected, the plume will develop at a slower rate than expected and be reflected in the pressure and CO<sub>2</sub> concentration data in 1 and 2 above.
- 4. A review of the full suite of water quality data collected from monitoring wells in addition to CO<sub>2</sub> content/saturation (to evaluate the potential for unexpected reactions between the injected fluid and the rock formation).
- 5. Review and submission of any geologic data acquired since the last modeling effort, including any additional site characterization performed for future injection wells.

- 6. Reevaluation modeling results will be compared with the most recent modeling (i.e., from the most recent AoR reevaluation). A report describing the comparison of the modeling results will be provided to the EPA with a discussion on whether the results are consistent.
- Description of the specific actions that will be taken if there are discrepancies between
  monitoring data and prior modeling results (e.g., remodel the AoR, update all project
  plans, perform additional corrective action if needed, and submit the results to EPA).

Re-evaluation results will be compared to the original results to understand dynamic inputs affecting plume development and static inputs that would impact injectivity and storage space. Static inputs that may potentially be considered to understand discrepancies between initial and re-evaluation computational models could include permeability, sand continuity and porosity. Although the AoR has been fully delineated, all inputs to the static and dynamic model will be reviewed.

As needed, CTV will review all of the plans that are impacted by a potential AoR increase such as Corrective Action and Emergency and Remedial Response. For corrective action, all wells potentially impacted by a changing AoR will be addressed immediately.

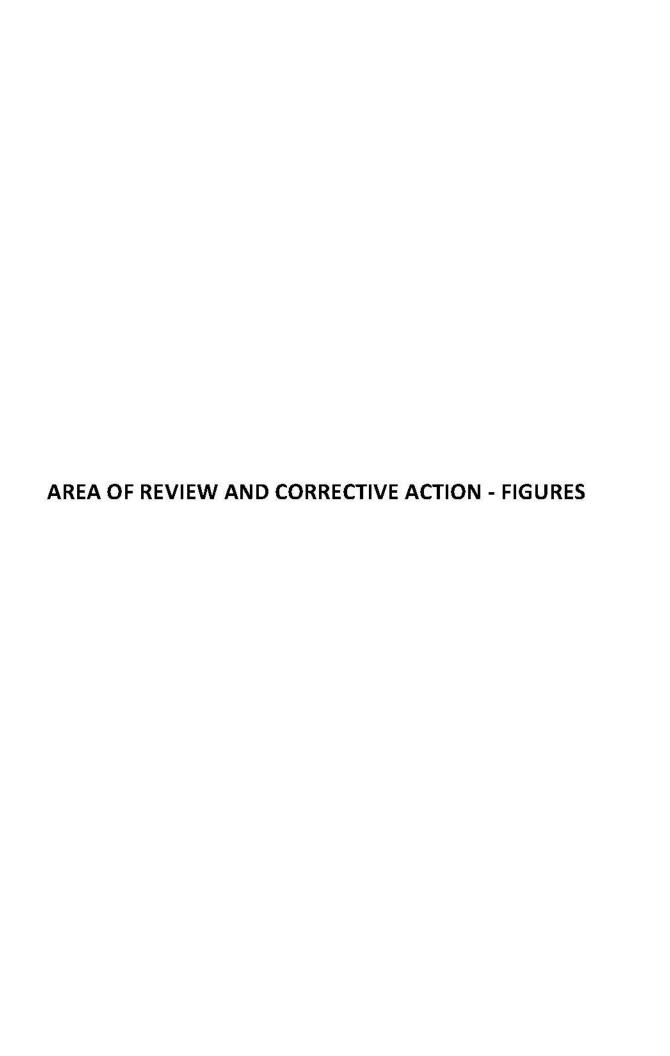
## 3.4.2 Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

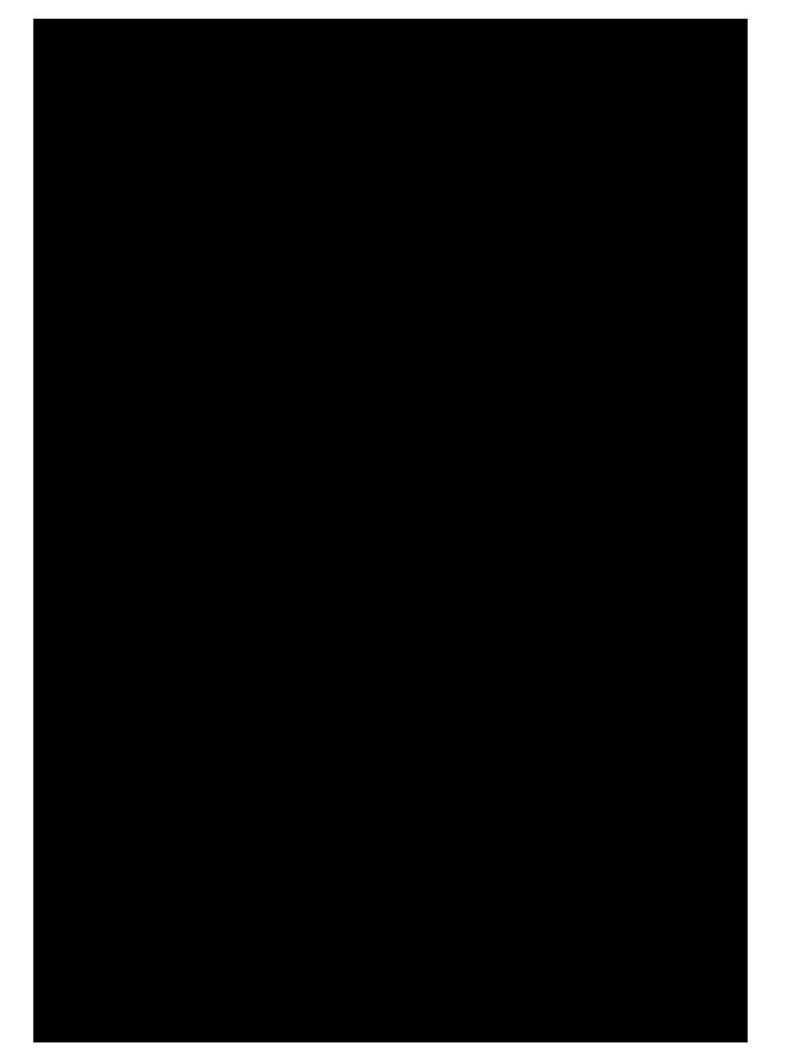
An ad-hoc re-evaluation prior to the next scheduled re-evaluation will be triggered if any of the following occur:

- 1. Changes in pressure or injection rate that are unexpected and outside three (3) standard deviations from the average will trigger a new evaluation of the AoR.
- 2. Difference between the computation modeling and observed plume development:
  - a. Unexpected changes in fluid constituents or pressure outside reservoir that are not related to well integrity.
  - b. Reservoir pressures increase versus injected volume is inconsistent with computational modeling results.
  - c. Any other activity prompting a model recalibration.
- 3. Seismic monitoring anomalies within two miles of the injection well that are indicative of:
  - a. The presence of faults near the confining zone that indicates propagation into the confining zone.
  - b. Events reasonably associated with CO<sub>2</sub> injection that are greater than M3.5.

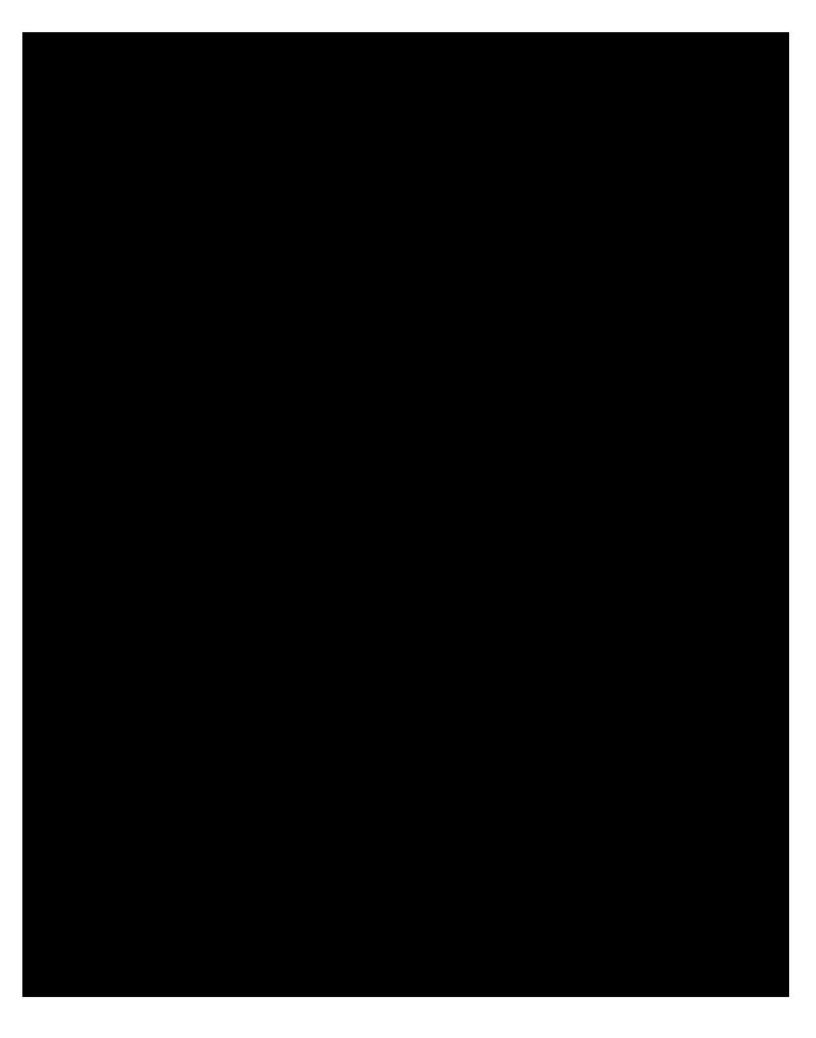
- Exceeding 90% of the geologic formation fracture pressure in any injection or monitoring wells.
- 3. Detection of changes in shallow groundwater chemistry (e.g., a significant increase in the concentration of any analytical parameter that was not anticipated by the AoR delineation modeling).
- Initiation of competing injection projects within the same injection formation within a 1mile radius of the injection well (including when additional CTV injection wells come online);
- 5. A significant change in injection operations, as measured by wellhead monitoring;
- 6. Significant land-use changes that would impact site access; and
- 7. Any other activity prompting a model recalibration.

CTV will discuss any such events with the UIC Program Director within six months of an event to determine if an AoR re-evaluation is required. If an unscheduled re-evaluation is triggered, CTV will perform the steps described at the beginning of this section of the Plan.











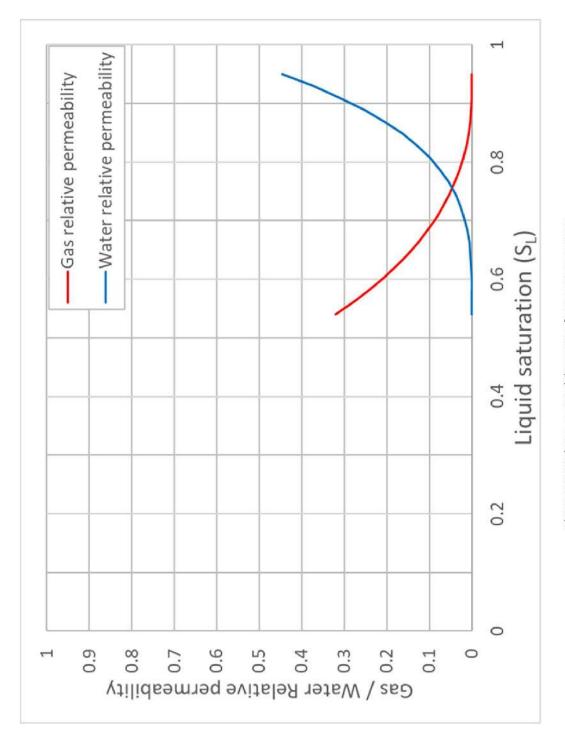


Figure 3.10: Relative permeability curves for Gas-Water system

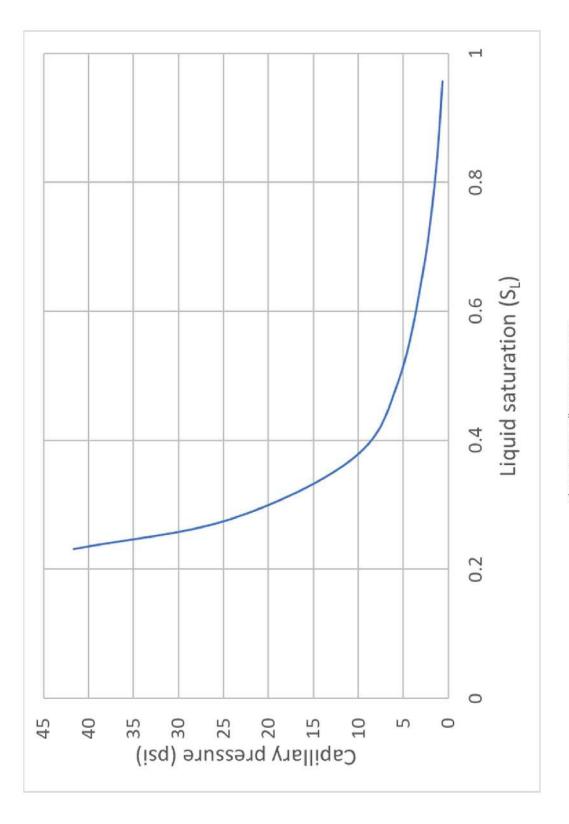
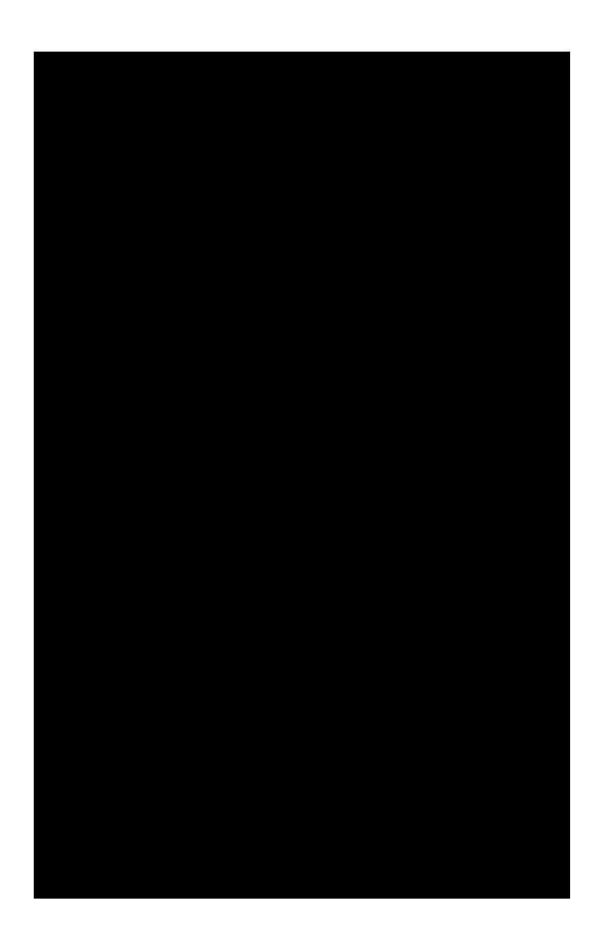
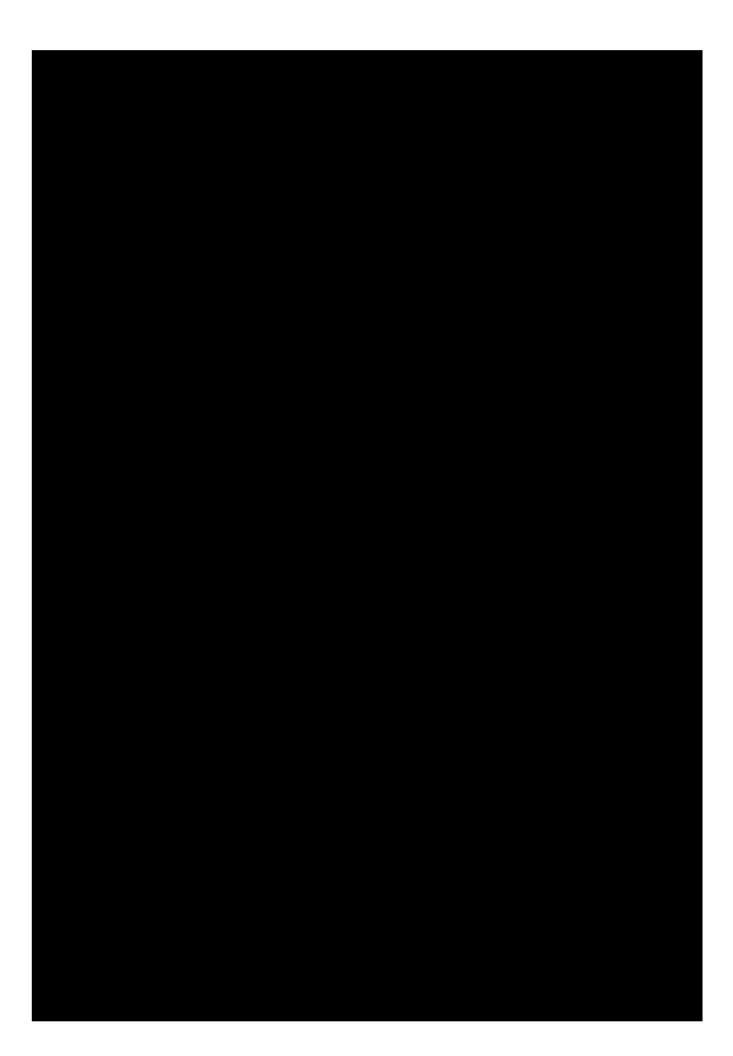


Figure 3.11: Capillary pressure curve









AREA OF REVIEW AND CORRECTIVE ACTION PLAN - TABLES

Table 3.1. Model domain information.

Coordinate System	State Plane				
HorizontalDatum	North American Datum (NAD) 27				
Coordinate System Units	Feet				
Zone	Zone 2				
FIPSZONE	0402	ADSZONE	3301		
Coordinate of X min		Coordinate of X max			
Coordinate of Y min	Coordinate of Y max				
Elevation of bottom of domain		Elevation of top of domain	1.5		

Table 3.2. Initial conditions.

Parameter	Value or Range	Units	Corresponding Elevation (ft MSL)	Data Source
Temperature	151	Fahrenheit		Bottom hole temperature data from logs in the area
Formation pressure	2860	Pounds per square inch		
Salinity	15,500	Parts per million		Water analysis and Log calculated salinity curves

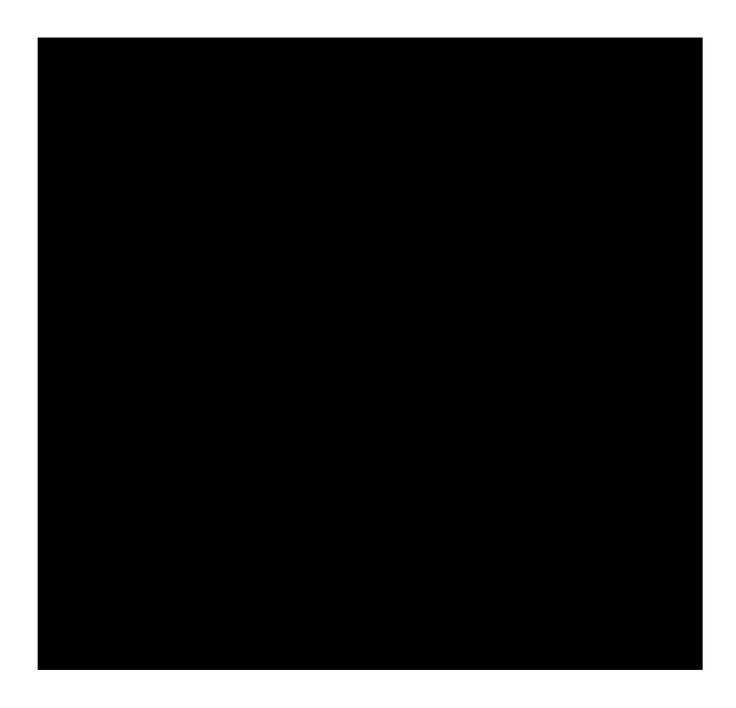


Table 3.4. Injection pressure details.

Injection Pressure Details	Injection Well C1	Injection Well C2	Injection Well E1	Injection Well E2	Injection Well W1	Injection Well W2
Fracture gradient (psi/ft)	0.76	0.76	0.76	0.76	0.76	0.76
Maximum allowable injection pressure (90% of fracture pressure) (psi)	4224	4919	4111	4774	4207	4802
Elevation corresponding to maximum injection pressure (ft TVD)	6178	7192	6011	6984	6155	7020
Elevation at the top of the perforated interval (ft TVD)	6178	7192	6011	6984	6155	7020
Calculated maximum injection pressure at the top of the perforated interval (psi)	4224	4919	4111	4774	4207	4802
Planned injection pressure (psi) / gradient (psi/ft) at top of perforations	3050 / 0.494	3566 / 0.496	2901 / 0.483	3363 / 0.482	2961 / 0.481	3504 / 0.499

 Table 3.5. Simulation sensitivity scenarios

Scenario	CO2 plume & AoR impact
Porosity: 10% reduction from base case	Minimal Impact
Porosity: 10% increase from base case	Minimal Impact
Permeability: 10% reduction from base case	Minimal Impact
Permeability: 10% increase from base case	Minimal Impact

#### **AOR DELINEATION**

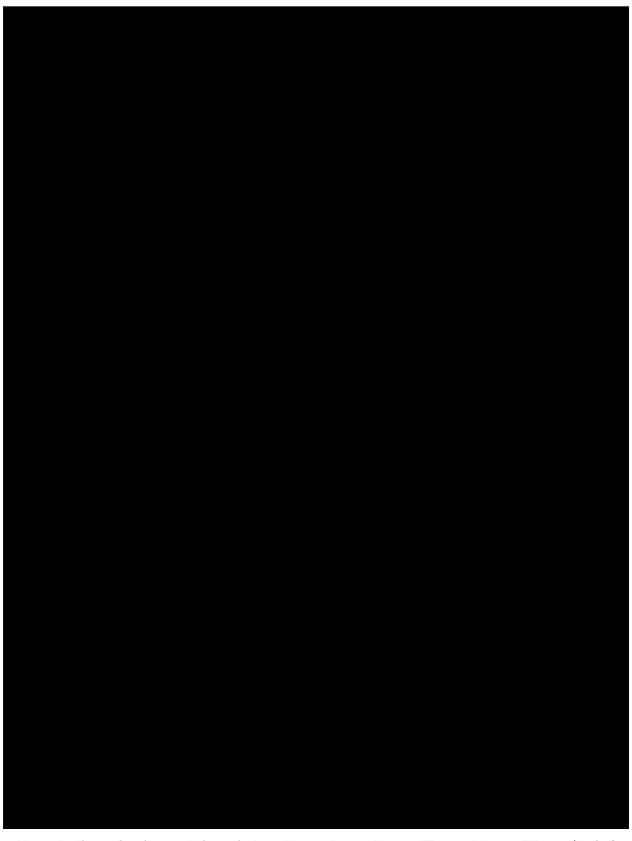
## **CTV III**

#### **Computational Modeling Results**

#### **Predictions of System Behavior**

The maps (**Figure 1**) and cross-sections (**Figure 2**) show the computational modeling results and development of the CO<sub>2</sub> plume at different time steps. The boundaries of the CO<sub>2</sub> plume have been defined with a  $0.01 \text{ CO}_2$  global mole fraction cutoff.

As shown in **Figure 1**, the  $CO_2$  extent is largely defined by year 52 after the end of injection. The majority of  $CO_2$  injectate remains as super-critical  $CO_2$  with the remaining portion of the  $CO_2$  dissolving in the formation brine over the simulated 100 years post injection.



**Figure 1.** Plume development through time: 1-year, 4-year, 6-year, 10-year, 16-year, 28-year (End of injection), 52-year post injection and 100-year post injection.

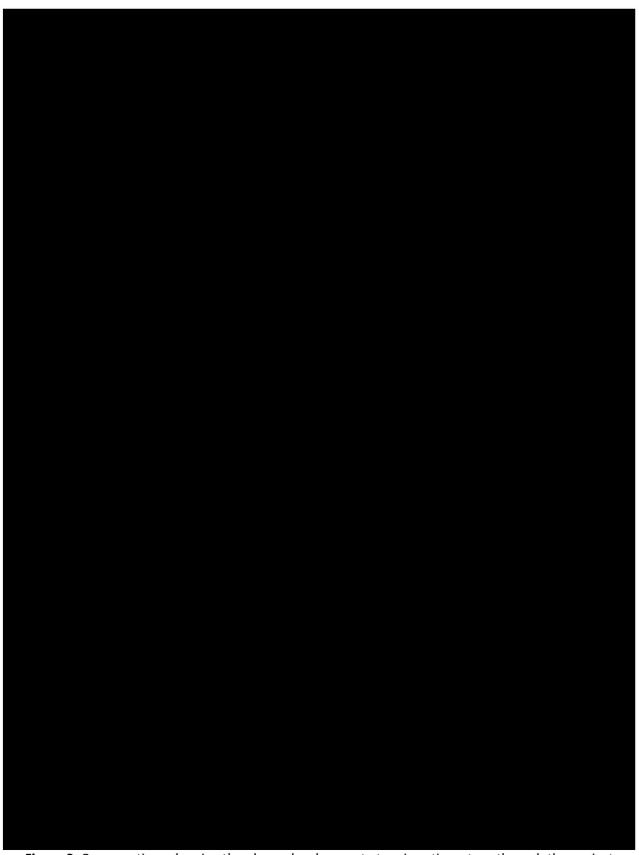


Figure 2. Cross-sections showing the plume development at various time steps through the project.

#### **AoR Delineation**

The AoR delineation was based on Critical pressure using the methods of Nicol et al. (2008), which is referenced in the US EPA AoR and Corrective Action Guidance. Based on pressure data available in the Mokelumne River formation in the region (Figure 3), it appears that the formation is underpressured. Graph and data table showing this are shown in Figure 4. This is likely due to historic withdrawal from the Mokelumne River formation from regional Gas field operations in the area, and limited recharge.



Figure 3. Mokelumne River Formation Pressure profile and data

For the purpose of calculating the critical pressure and delineating the AoR for the project area, the aquifer was considered to be under-pressured by psi, and the following equations were used to calculate critical pressure across the model domain:

$$\Delta P_{C,norm} = g(Z_V - Z_I) \left[ \frac{\lambda - \xi}{2} (Z_V - Z_I) + \rho_{I,\lambda} - \rho_I \right]$$
- Eq (1)

 $\Delta P_c = \Delta P_{C,norm} + \Delta P_u$  - Eq (2)

Where,

 $\Delta P_{C,norm}$  - the admissible overpressure in a normally pressured aquifer before fluid in the injection zone would flow into the USDW through a hypothetical open conduit

 $\Delta P_c$  - the admissible overpressure in an under-pressured aquifer before fluid in the injection zone would flow into the USDW through a hypothetical open conduit

 $\Delta P_u$  - the difference of normal pressure to actual pressure in the under-pressured aguifer, assumed psi across the model domain

g - acceleration due to gravity, 9.81m/s<sup>2</sup>

 $Z_V$  - Elevation of the injection zone

 $Z_I$  - Elevation of the base of the USDW

density gradient in the conduit at constant injection zone brine TDS

ξ - density gradient in the conduit at initial condition

 $ho_{I,\lambda}$  - Density of the injection zone brine at USDW depth

 $ho_I$  - Density of the brine in the conduit at USDW depth at initial condition

An average TDS of 15,500ppm was assumed for the injection zone and an average TDS of 7,900ppm was assumed for the USDW based on Salinity calculations in the project area. Injection zone and USDW depths were based on the model grid and USDW mapping in the project area. Density and density gradients were calculated as a function of temperature and salinity using standard methods (McCutcheon et. al. 1993). Using these, the critical pressure was calculated at each grid point in the Petrel model using Equations 1 & 2 and combined with the pressure outputs from the plume simulation to delineate an AoR boundary at different timesteps. The final AoR boundary was based on the outermost threshold overpressure 14years into the injection which is when the maximum extent was seen. Figure 5 shows the AoR boundary, CO2 plume extent, injection wells and proposed monitoring wells. 50 years after the end of injection, the pressure buildup in the reservoir dissipates to approximately zero.

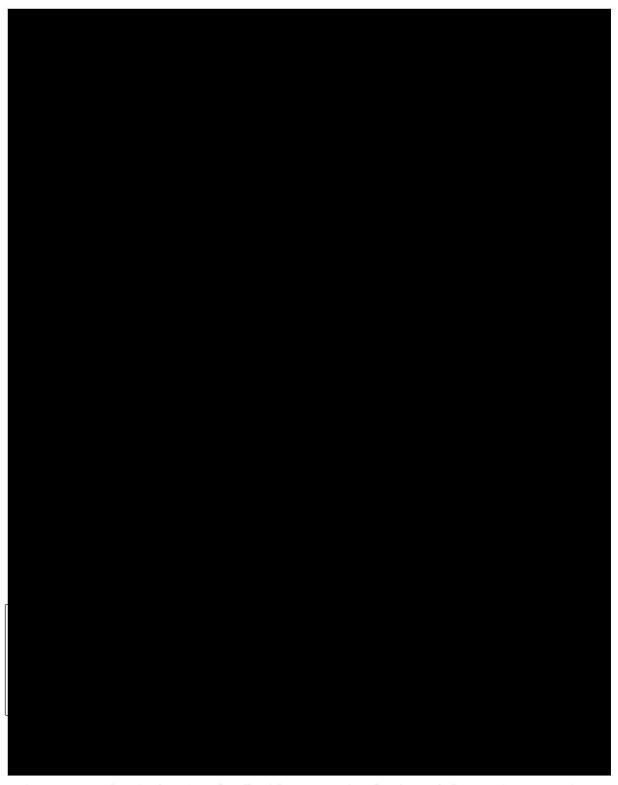


Figure 4. Map showing location of wells with pressure data for the Mokelumne River Formation.

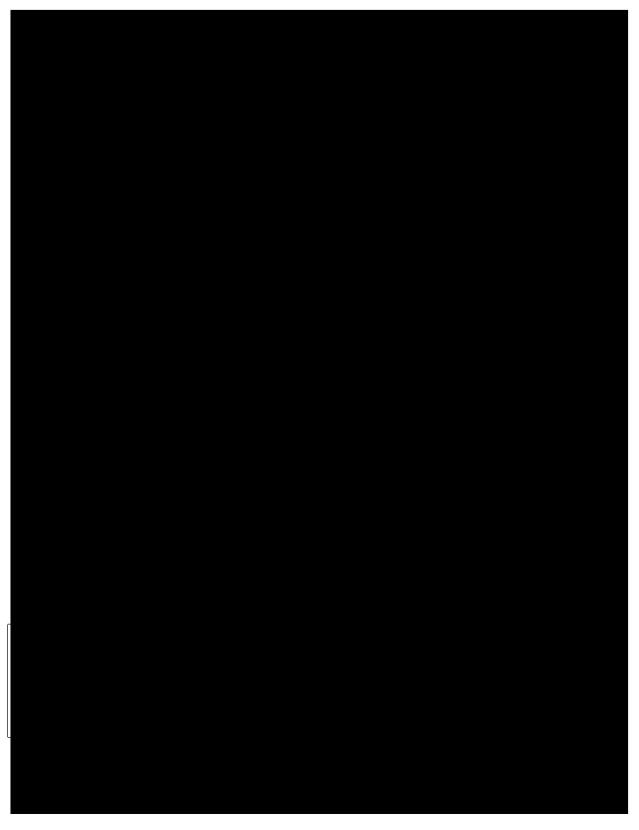


Figure 5: Map showing the location of injection wells and plume monitoring wells.

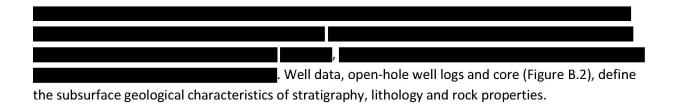
# AOR BOUNDARY CONDITIONS DESCRIPTION CTV III

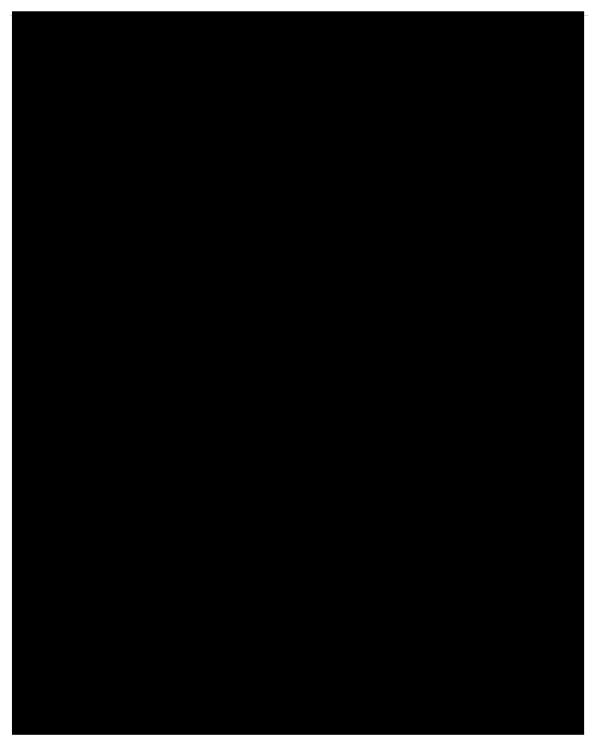
## **AoR Boundary Conditions**

Site Geology and Hydrology
~200 feet in the model domain area and has very low matrix permeability. Its competence in
confining upward fluid movement is established by its demonstrated historical performance



**Figure 1:** Cross section showing stratigraphy, type wells and the lateral continuity of major formations in the AoR.

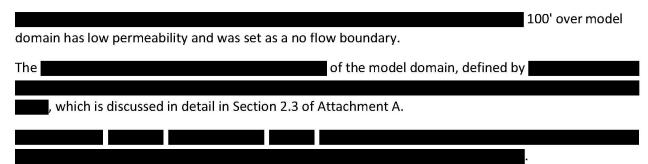




**Figure 2:** Location of wells with open-hole log and relative permeability or capillary pressure data used to develop the static model used in computation modeling.

## **Boundary Conditions**

The following Boundary conditions were applied to the model domain:



## CAPILLARY PRESSURE CTV III

## **Capillary Pressure**

As no site specific capillary pressure was available, data obtained from core from were used for the computational simulation. The simulation and AoR will be updated once site specific core data is obtained during the Pre-operational testing phase. Figure 1 shows the capillary pressure curve used in the computational modeling.

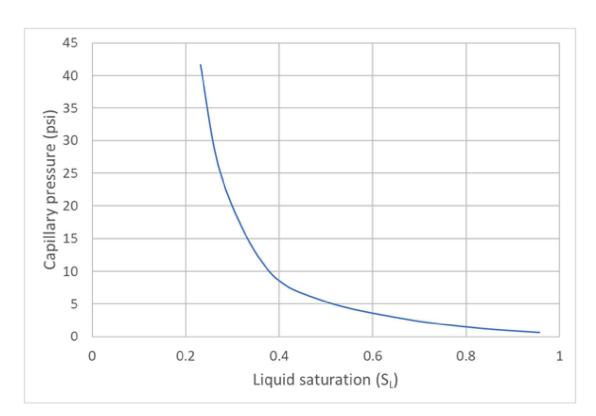


Figure 1: Capillary Pressure curve for Gas-Water system

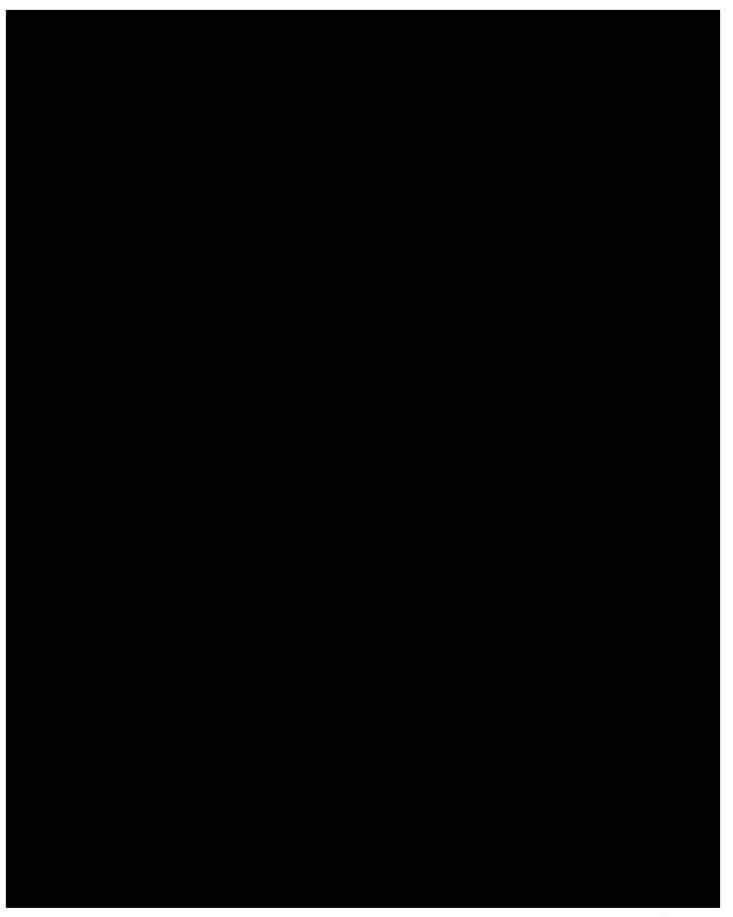
## COMPUTATIONAL MODELING RESULTS TIME SERIES CTV III

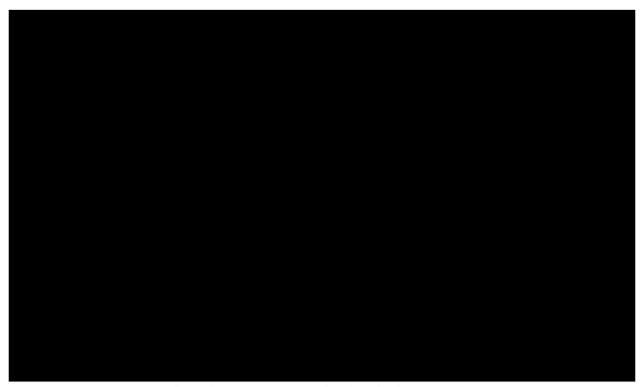
### **Predictions of Systems Behavior**

The following maps (**Figure 1**) and cross-sections (**Figure 2**) show the computational modeling results and development of the CO<sub>2</sub> plume at different time steps. The boundaries of the CO<sub>2</sub> plume have been defined with a 0.01 CO<sub>2</sub> global mole fraction cutoff.

As shown in **Figure 1**, the CO<sub>2</sub> extent is largely defined by year 52 after the end of injection. The majority of CO<sub>2</sub> injectate remains as super-critical CO<sub>2</sub> (83%) with the remaining portion of the CO<sub>2</sub> dissolving in the formation brine over the simulated 100 years post injection. **Figure 3** shows the modeled results of the total CO<sub>2</sub> injected, the amounts stored in Supercritical phase and amounts dissolved in brine over time.







**Figure 3.** CO2 storage mechanisms in the reservoir.

## CRITICAL PRESSURE CALCULATION CTV III

#### **Critical Pressure Calculation**

The Critical pressure was calculated using the methods of Nicol et al. (2008), which is referenced in the US EPA AoR and Corrective Action Guidance.



Figure 1. Pressure profile and data

For the purpose of calculating the critical pressure and delineating the AoR for the project area, and the following equations were used to calculate critical pressure across the model domain:

$$\Delta P_{C,norm} = g(Z_V - Z_I) \left[ \frac{\lambda - \xi}{2} (Z_V - Z_I) + \rho_{I,\lambda} - \rho_I \right] - \text{Eq (1)}$$

$$\Delta P_c = \Delta P_{C,norm} + \Delta P_u$$
 - Eq (2)

Where,

 $\Delta P_{C,norm}$  - the admissible overpressure in a normally pressured aquifer before fluid in the injection zone would flow into the USDW through a hypothetical open conduit

 $\Delta P_c$  - the admissible overpressure in an under-pressured aquifer before fluid in the injection zone would flow into the USDW through a hypothetical open conduit

 $\Delta P_u$  - the difference of normal pressure to actual pressure in the under-pressured aguifer, assumed psi across the model domain

g - acceleration due to gravity, 9.81m/s<sup>2</sup>

 $Z_V$  - Elevation of the injection zone

 $Z_I$  - Elevation of the base of the USDW

 $\lambda$  - density gradient in the conduit at constant injection zone brine TDS

 $\boldsymbol{\xi}$  — density gradient in the conduit at initial condition

 $ho_{I,\lambda}$  - Density of the injection zone brine at USDW depth

 $ho_I$  - Density of the brine in the conduit at USDW depth at initial condition

An average TDS of 15,500ppm was assumed for the injection zone and an average TDS of 7,900ppm was assumed for the USDW based on Salinity calculations in the project area. Injection zone and USDW depths were based on the model grid and USDW mapping in the project area. Density and density gradients were calculated as a function of temperature and salinity using standard methods (McCutcheon et. al. 1993). Using these, the critical pressure was calculated at each grid point in the Petrel model using Equations 1 & 2 and combined with the pressure outputs from the plume simulation to delineate an AoR boundary at different timesteps. The final AoR boundary was based on the outermost threshold overpressure 14 years into injection which is when the maximum extent was seen. 50 years after the end of injection, the pressure buildup in the reservoir dissipates to approximately zero.

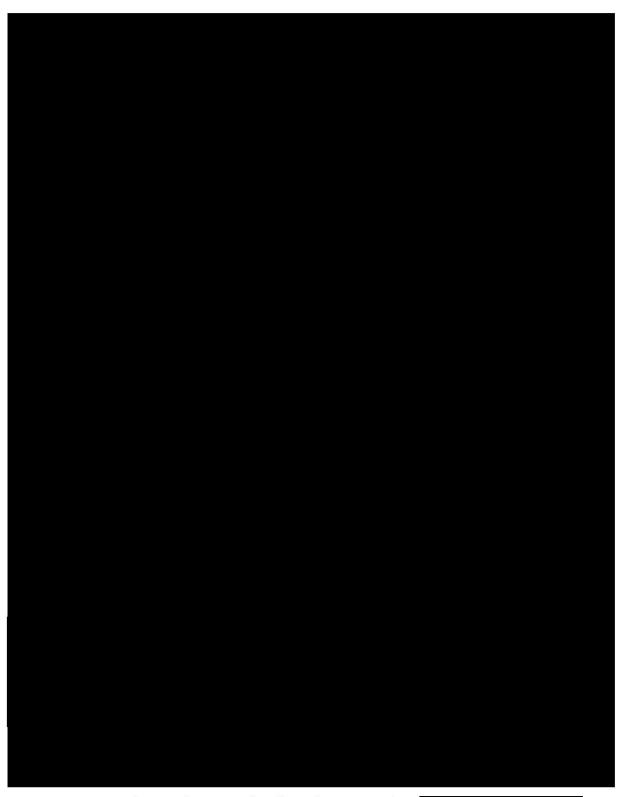


Figure 3. Map showing location of wells with pressure data

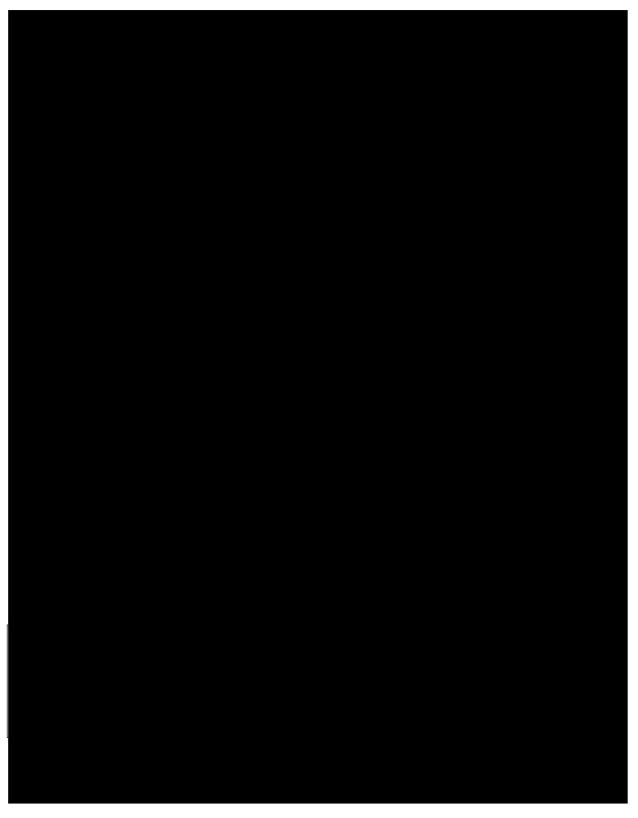


Figure 5: Map showing the location of injection wells and plume monitoring wells.

# GRID DESCRIPTION CTV III

#### **Model Domain**

A static geological model developed with Schlumberger's Petrel software, commonly used in the petroleum industry for exploration and production, is the computational modeling input. It allows the user to incorporate seismic and well data to build reservoir models and visualize reservoir simulation results. Model domain information is summarized in **Table 1**.

Table 1. Model domain information.

Coordinate System	State Plane			
Horizontal Datum	North American Datum (NAD) 27			
Coordinate System Units	Feet			
Zone	Zone 2			
FIPSZONE		ADSZONE		
Coordinate of X min		Coordinate of X max		
Coordinate of Y min		Coordinate of Y max		
Elevation of bottom of domain		Elevation of top of domain		

· · · · · · · · · · · · · · · · · · ·
A Tartan grid with varying cell XY dimensions
the model demain as shown in Figure 3
the model domain as shown in <b>Figure 2</b> .
In the CO <sub>2</sub> plume area, the grid cells are
predominantly 500'x500' but some cells are as small as 50'x50' in the region immediately around
the planned injectors. The grid cell size increases with greater distance away from the main
injection area, where cells up to 1000'x1000' cover the areas of the model that are furthest from
the injectors.

As illustrated in Figure 2,	

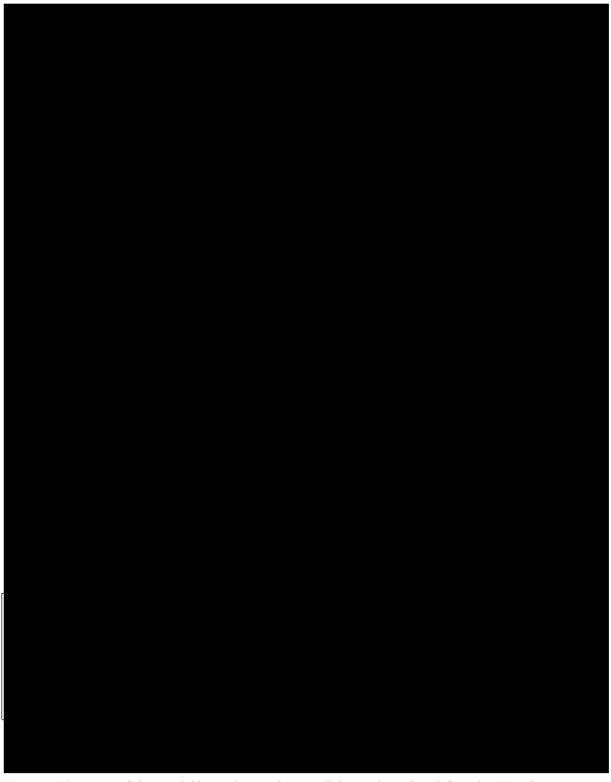
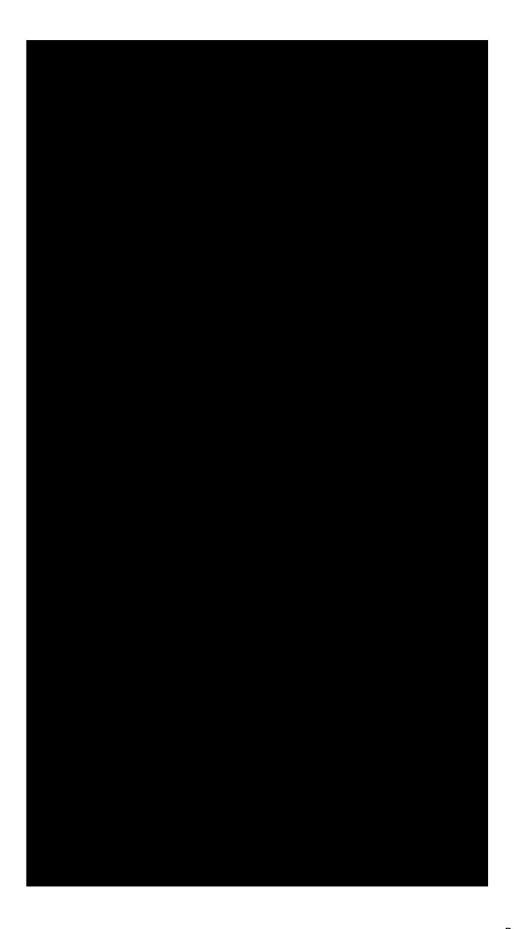


Figure 2. Plan view of the model boundary and geo-cellular grid used to define the CO<sub>2</sub> plume extent and associated AoR.

A constant vertical cell height of 20 feet was utilized over the model domain to generate grid layers within the model as shown in **Figure 3**. The 20-foot cell height provides the vertical resolution necessary to capture significant lithologic heterogeneity (sand versus shale) which helps to ensure accurate upscaling of log data and distribution of reservoir properties in the static model. **Figure 4** shows a comparison of open-hole log data and the associated upscaled logs for a well within the AoR.





## PERMEABILITY DETERMINATION CTV III

#### **Model Permeability**

#### Static Modeling Permeability

Wireline log data was acquired with measurements that include but are not limited to spontaneous potential, natural gamma ray, borehole caliper, compressional sonic, resistivity as well as neutron porosity and bulk density.

Formation porosity is determined one of two ways: from bulk density using 2.65 g/cc matrix density as calibrated from core grain density and core porosity data, or from compressional sonic using  $55.5 \,\mu sec/ft$  matrix slowness and the Raymer-Hunt equation.

Volume of clay is determined by spontaneous potential and is calibrated to core data.

Log-derived permeability is determined by applying a core-based transform that utilizes capillary pressure porosity and permeability along with clay values from XRD or FTIR. Core data from two wells with 13 data points was used to develop a permeability transform (**Figure 3**). An example of the transform from core data is illustrated in **Figure 1**.

Figure 2 shows porosity and permeability histograms feet the state of the state of

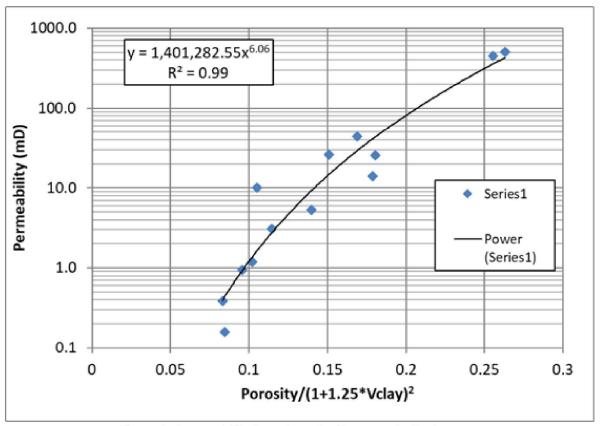


Figure 1: Permeability transform for Sacramento Basin zones

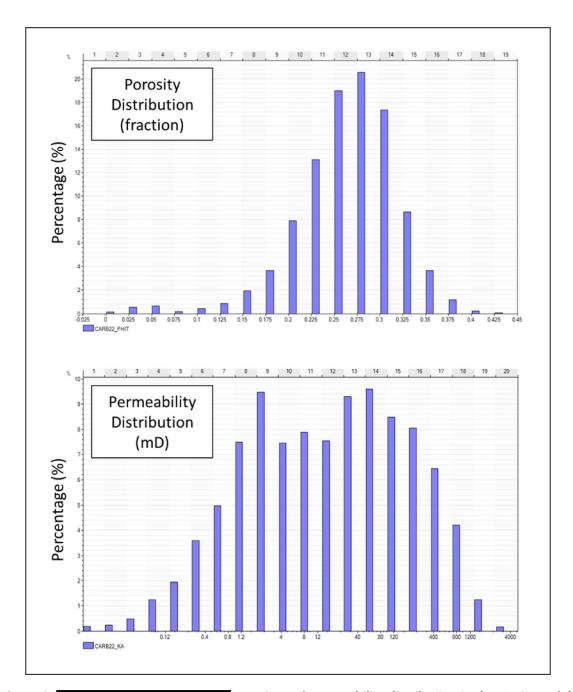


Figure 2: porosity and permeability distribution in the static model.





# PERMEABILITY DISTRIBUTION CTV III

### **Permeability Distribution**

Figure 1 shows porosity and permeability histograms in the static geocellular model. Porosity is derived from open-hole well log analysis and permeability is a function of porosity and clay volume. Figure 2 shows the permeability and porosity distribution in cross-section A-A'.

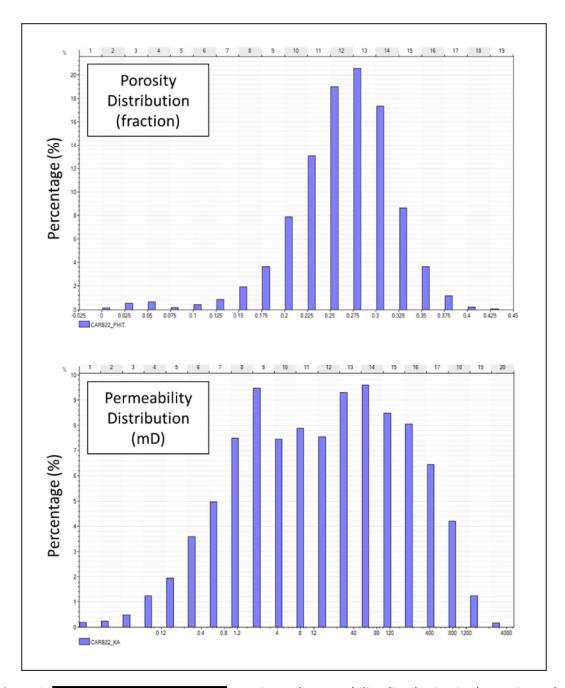


Figure 1: porosity and permeability distribution in the static model.



## POROSITY DETERMINATION CTV III

### **Model Porosity**

#### Static Modeling Porosity

Wireline log data was acquired with measurements that include but are not limited to spontaneous potential, natural gamma ray, borehole caliper, compressional sonic, resistivity as well as neutron porosity and bulk density.

Formation porosity is determined one of two ways: from bulk density using 2.65 g/cc matrix density as calibrated from core grain density and core porosity data, or from compressional sonic using 55.5  $\mu$ sec/ft matrix slowness and the Raymer-Hunt equation.

Volume of clay is determined by spontaneous potential and is calibrated to core data.

Log-derived permeability is determined by applying a core-based transform that utilizes capillary pressure porosity and permeability along with clay values from XRD or FTIR. Core data from two wells with 13 data points was used to develop a permeability transform (**Figure 3**). An example of the transform from core data is illustrated in **Figure 1**.

Figure 2 shows porosity and permeability histograms . Porosity is derived from open-hole well log analysis and permeability is a function of porosity and clay volume. Figure 4 shows the distribution of permeability and porosity using Sequential Gaussian simulation (kriging) within the static model.

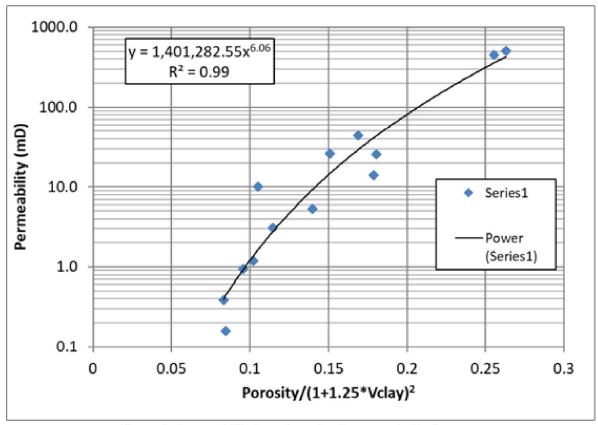


Figure 1: Permeability transform for Sacramento Basin zones

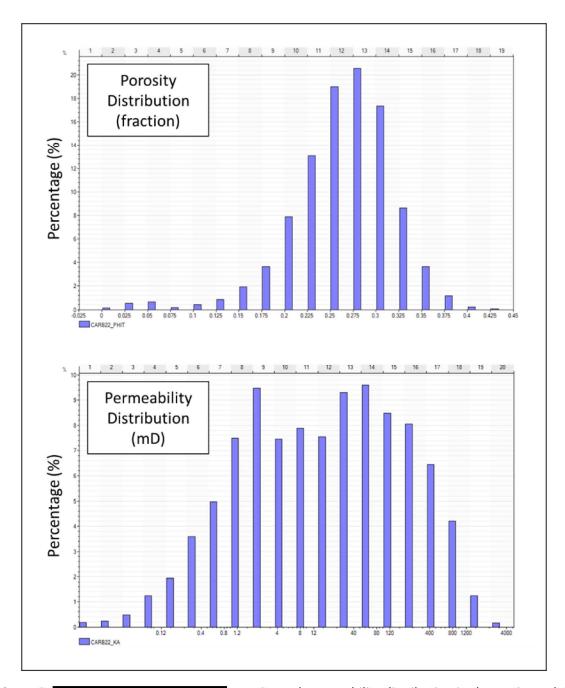


Figure 2: porosity and permeability distribution in the static model.

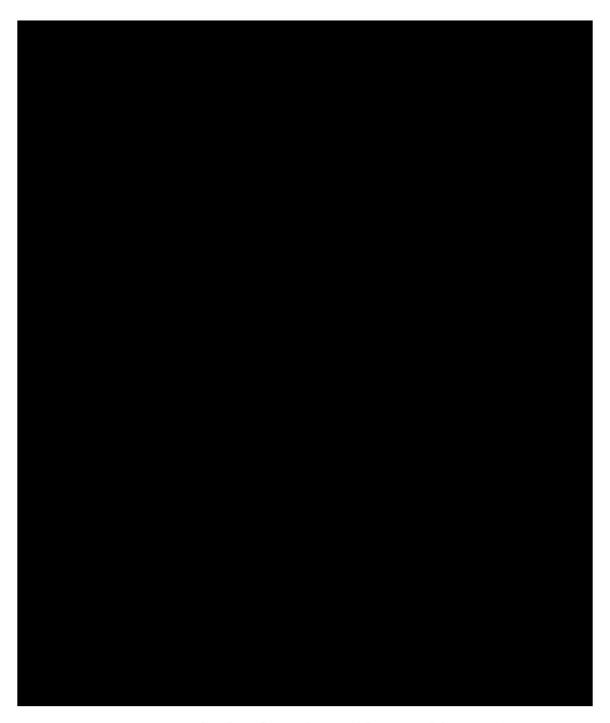
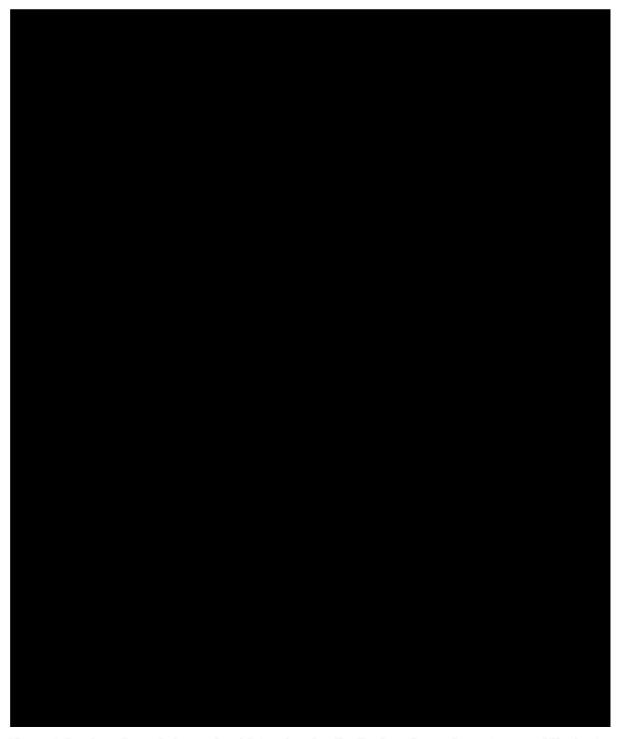


Figure 3: Location of wells with core data used for permeability transform.



**Figure 4:** Sections through the static grid showing the distribution of porosity and permeability in the reservoir.

# POROSITY DISTRIBUTION CTV III

### **Porosity Distribution**

Figure 1 shows porosity and permeability histograms in the static geocellular model. Porosity is derived from open-hole well log analysis and permeability is a function of porosity and clay volume. Figure 2 shows the permeability and porosity distribution in cross-section A-A'.

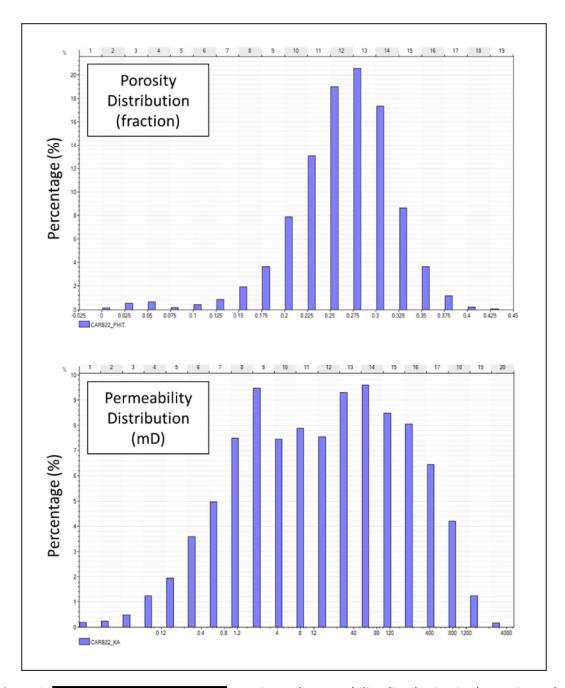


Figure 1: porosity and permeability distribution in the static model.



## RELATIVE PERMEABILITY CTV III

### **Relative Permeability**

As no site specific relative permeability was available, were used for the computational simulation. The simulation and AoR will be updated once site specific core data is obtained during the Pre-operational testing phase. Figure 1 shows the relative permeability curve used in the computational modeling.

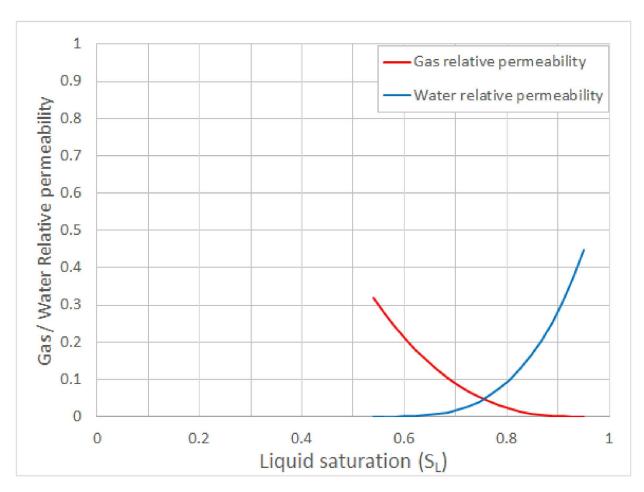


Figure 1: Relative permeability curves for Gas-Water system



## RELATIVE PERMEABILITY CTV III

### **Relative Permeability**

As no site specific relative permeability was available, were used for the computational simulation. The simulation and AoR will be updated once site specific core data is obtained during the Pre-operational testing phase. Figure 1 shows the relative permeability curve used in the computational modeling.

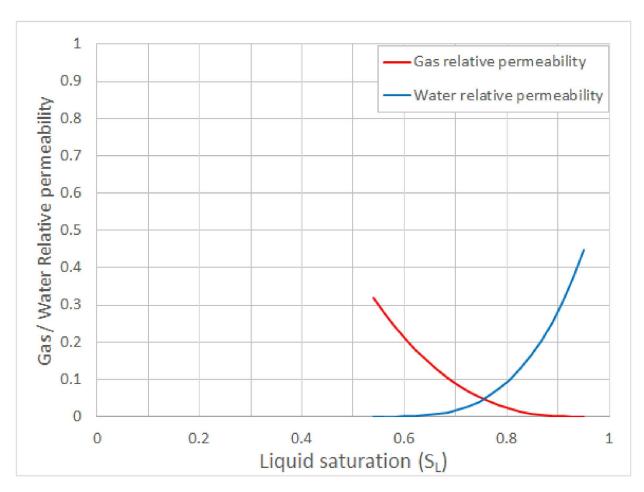


Figure 1: Relative permeability curves for Gas-Water system



#### **ROCK TYPE**

Rock Type and Depositional Environment

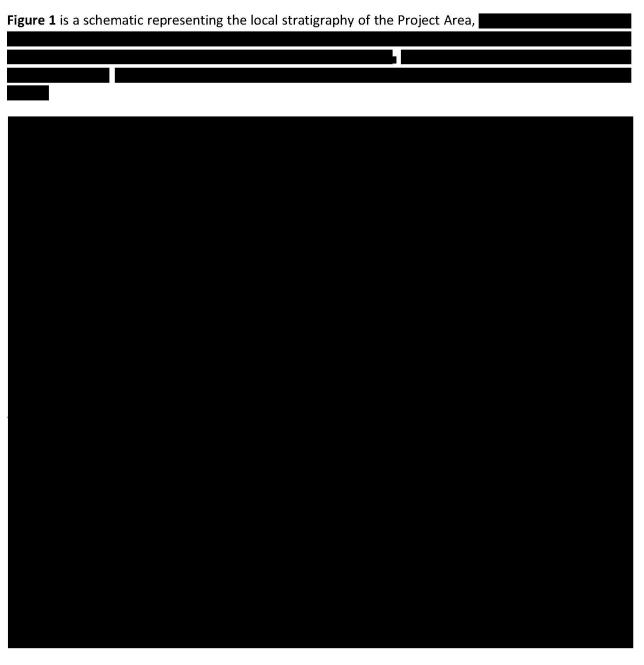
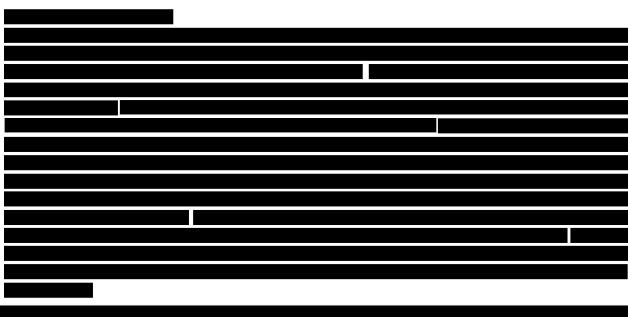
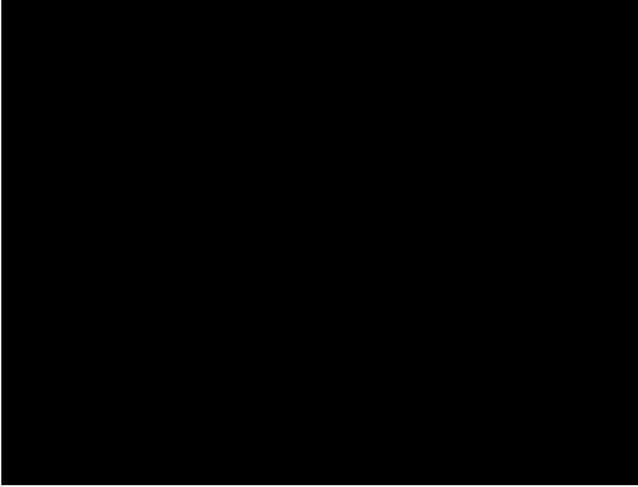


Figure 1. Schematic west to east cross section in the Sacramento basin.

Following its deposition,					v	vhich carrie:
throughout most of its dis	tribution.	This formation	serves as the p	primary upper	confining 2	zone for the
	due to i	ts low permea	bility, thickness	s, and regional	continuity	that spans
beyond the AoR.						





#### **ROCK TYPE DISTRIBUTION**

**Rock Type and Depositional Environment** 

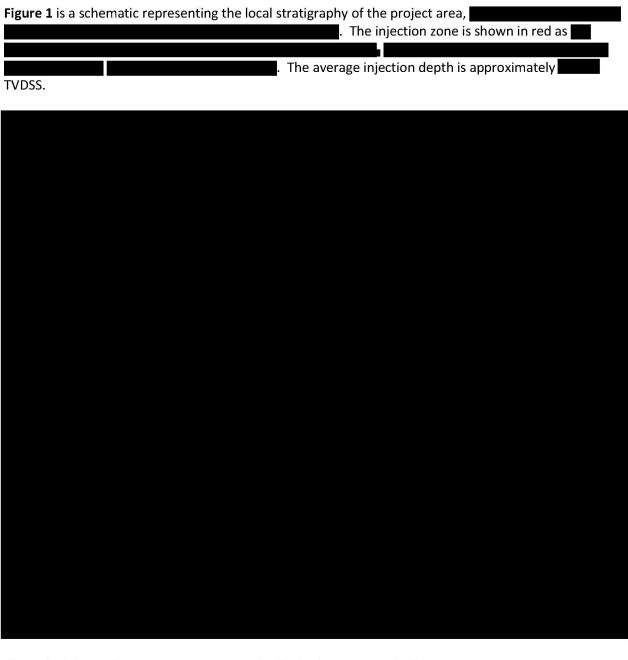
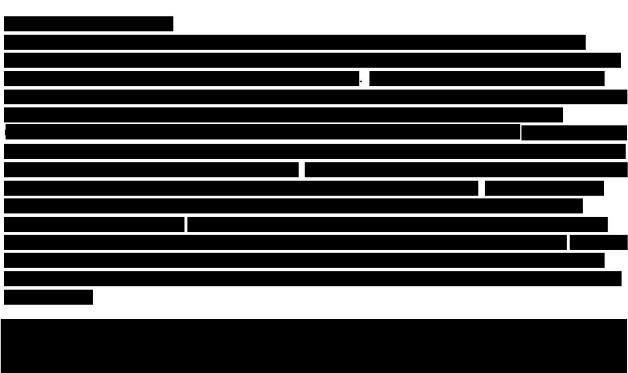
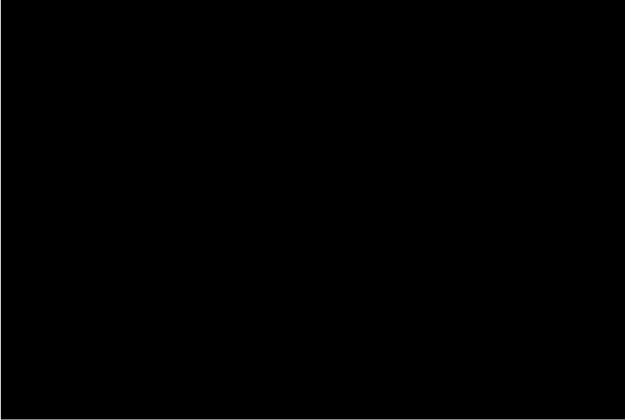


Figure 1. Schematic west to east cross section in the Sacramento basin.

Following its deposition,		which
carries throughout most of its distr	ribution. This formation serves as the primary upper conf	ining zone
for	due to its low permeability, thickness, and regional conti	nuity that
spans beyond the AoR. Above the		





### **CTV III Project Confidentiality**

The following are proprietary to CTV and considered confidential:

- 1. Geological and computational modeling files
- 2. Wellbore diagrams and wellbore records
- 3. Project location
- 4. Financial Information
- 5. Corrective action assessment results

Requests for these files can be made to Travis Hurst.

Phone: 661-342-2409

Email: Travis.Hurst@crc.com

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## FRACTURE GRADIENT AND MAXIMUM INJECTION PRESSURE INJECTOR C1

## **Fracture gradient**

A fracture pressure gradient of 0.76	psi/ft is assumed for the injection zone. This is based on formation
integrity tests in the	conducted on wells -
	. CTV will conduct a step rate test in the injection zone as part
of the pre-operational testing plan to	confirm this fracture pressure gradient.

## **Maximum Injection Pressure**

CTV will ensure that the injection pressure is below 90% of the injection zone fracture gradient at the top of perforations in the injection well (Table 1). CTV expects to operate the wells with a planned bottom hole injection pressure well below the maximum allowable injection pressure calculated using the fracture gradient and safety factor.

Table 1: Maximum Injection pressure

Injection Pressure Details	Injection Well C1
Fracture gradient (psi/ft)	0.76
Maximum allowable injection pressure (90% of fracture pressure) (psi)	4224
Elevation corresponding to maximum injection pressure (ft TVD)	6178
Elevation at the top of the perforated interval (ft TVD)	6178

# WELLBORE DIAMETER INJECTOR C1

Depth Interv		Open Hole Diameter	Outer Diameter	Inner Diameter
Casing	(feet)	(Inches)	(inches)	(inches)
Conductor	14' - 54'	24	20	19.124
Surface	14' - 600'	17.5	13.375	12.615
Intermediate	14' - 2550'	12.25	9.675	8.755
Long-String	14' - 5780' 5780' - 7895'	8.5	7	6.276

## FRACTURE GRADIENT AND MAXIMUM INJECTION PRESSURE INJECTOR C2

## **Fracture gradient**

A fracture pressure gradient of 0.76	psi/ft is assumed for the injection zone. This is based on formation
integrity tests in the	conducted on wells -
	. CTV will conduct a step rate test in the injection zone as part
of the pre-operational testing plan to	o confirm this fracture pressure gradient.

## **Maximum Injection Pressure**

CTV will ensure that the injection pressure is below 90% of the injection zone fracture gradient at the top of perforations in the injection well (Table 1). CTV expects to operate the wells with a planned bottom hole injection pressure well below the maximum allowable injection pressure calculated using the fracture gradient and safety factor.

Table 1: Maximum Injection pressure

Injection Pressure Details	Injection Well C2
Fracture gradient (psi/ft)	0.76
Maximum allowable injection pressure (90% of fracture pressure) (psi)	4919
Elevation corresponding to maximum injection pressure (ft TVD)	7192
Elevation at the top of the perforated interval (ft TVD)	7192

# WELLBORE DIAMETER INJECTOR C2

Depth Interval		Open Hole Diameter	Outer Diameter	Inner Diameter
Casing	(feet)	(Inches)	(inches)	(inches)
Conductor	14' - 54'	24	20	19.124
Surface	14' - 600'	17.5	13.375	12.615
Intermediate	14' - 2550'	12.25	9.675	8.755
Long-String	14' - 5760' 5760' - 7910'	8.5	7	6.276

## FRACTURE GRADIENT AND MAXIMUM INJECTION PRESSURE INJECTOR E1

## **Fracture gradient**

A fracture pressure gradient of 0.7	'6 psi/ft is assumed for the injection zone. This is based on formation
integrity tests in the	conducted on wells -
	. CTV will conduct a step rate test in the injection zone as part
of the pre-operational testing plan	to confirm this fracture pressure gradient.

## **Maximum Injection Pressure**

CTV will ensure that the injection pressure is below 90% of the injection zone fracture gradient at the top of perforations in the injection well (Table 1). CTV expects to operate the wells with a planned bottom hole injection pressure well below the maximum allowable injection pressure calculated using the fracture gradient and safety factor.

Table 1: Maximum Injection pressure

Injection Pressure Details	Injection Well E1
Fracture gradient (psi/ft)	0.76
Maximum allowable injection pressure (90% of fracture pressure) (psi)	4111
Elevation corresponding to maximum injection pressure (ft TVD)	6011
Elevation at the top of the perforated interval (ft TVD)	6011

# WELLBORE DIAMETER INJECTOR E1

	Depth Interval		Outer Diameter	Inner Diameter
Casing	(feet)	(Inches)	(inches)	(inches)
Conductor	14' - 54'	24	20	19.124
Surface	14' - 600'	17.5	13.375	12.615
Intermediate	14' - 2550'	12.25	9.675	8.755
Long-String	14' - 5570' 5570' - 7855'	8.5	7	6.276

## FRACTURE GRADIENT AND MAXIMUM INJECTION PRESSURE INJECTOR E2

## **Fracture gradient**

A fracture pressure gradi	ent of 0.76 psi/ft is assumed for the injection zone. This is based on formation
integrity tests in the	conducted on wells -
	. CTV will conduct a step rate test in the injection zone as part
of the pre-operational tes	sting plan to confirm this fracture pressure gradient.

## **Maximum Injection Pressure**

CTV will ensure that the injection pressure is below 90% of the injection zone fracture gradient at the top of perforations in the injection well (Table 1). CTV expects to operate the wells with a planned bottom hole injection pressure well below the maximum allowable injection pressure calculated using the fracture gradient and safety factor.

Table 1: Maximum Injection pressure

Injection Pressure Details	Injection Well E2
Fracture gradient (psi/ft)	0.76
Maximum allowable injection pressure (90% of fracture pressure) (psi)	4774
Elevation corresponding to maximum injection pressure (ft TVD)	6984
Elevation at the top of the perforated interval (ft TVD)	6984

# WELLBORE DIAMETER INJECTOR E2

Depth Interval		Open Hole Diameter	Outer Diameter	Inner Diameter
Casing	(feet)	(Inches)	(inches)	(inches)
Conductor	14' - 54'	24	20	19.124
Surface	14' - 600'	17.5	13.375	12.615
Intermediate	14' - 2550'	12.25	9.675	8.755
Long-String	14' - 5570' 5570' - 7845'	8.5	7	6.276

## FRACTURE GRADIENT AND MAXIMUM INJECTION PRESSURE INJECTOR W1

## **Fracture gradient**

A fracture pressure grad	dient of 0.76 psi/ft is assumed for the injection zone. This is based on formation
integrity tests in the	conducted on wells -
	. CTV will conduct a step rate test in the injection zone as part
of the pre-operational t	esting plan to confirm this fracture pressure gradient.

## **Maximum Injection Pressure**

CTV will ensure that the injection pressure is below 90% of the injection zone fracture gradient at the top of perforations in the injection well (Table 1). CTV expects to operate the wells with a planned bottom hole injection pressure well below the maximum allowable injection pressure calculated using the fracture gradient and safety factor.

Table 1: Maximum Injection pressure

Injection Pressure Details	Injection Well W1
Fracture gradient (psi/ft)	0.76
Maximum allowable injection pressure (90% of fracture pressure) (psi)	4207
Elevation corresponding to maximum injection pressure (ft TVD)	6155
Elevation at the top of the perforated interval (ft TVD)	6155

# WELLBORE DIAMETER INJECTOR W1

Casing	Depth Interval	Open Hole Diameter	Outer Diameter	Inner Diameter
	(feet)	(Inches)	(inches)	(inches)
Conductor	14' - 54'	24	20	19.124
Surface	14' - 600'	17.5	13.375	12.615
Intermediate	14' - 2550'	12.25	9.675	8.755
Long-String	14' - 5780' 5780' - 7895'	8.5	7	6.276

## FRACTURE GRADIENT AND MAXIMUM INJECTION PRESSURE INJECTOR W2

## **Fracture gradient**

A fracture pressure gradient of 0.76	psi/ft is assumed for the injection zone. This is based on formation
integrity tests in the	conducted on wells -
	. CTV will conduct a step rate test in the injection zone as part
of the pre-operational testing plan to	confirm this fracture pressure gradient.

## **Maximum Injection Pressure**

CTV will ensure that the injection pressure is below 90% of the injection zone fracture gradient at the top of perforations in the injection well (Table 1). CTV expects to operate the wells with a planned bottom hole injection pressure well below the maximum allowable injection pressure calculated using the fracture gradient and safety factor.

Table 1: Maximum Injection pressure

Injection Pressure Details	Injection Well W2
Fracture gradient (psi/ft)	0.76
Maximum allowable injection pressure (90% of fracture pressure) (psi)	4802
Elevation corresponding to maximum injection pressure (ft TVD)	7020
Elevation at the top of the perforated interval (ft TVD)	7020

# WELLBORE DIAMETER INJECTOR W2

Casing	Depth Interval	Open Hole Diameter	Outer Diameter	Inner Diameter
	(feet)	(Inches)	(inches)	(inches)
Conductor	14' - 54'	24	20	19.124
Surface	14' - 600'	17.5	13.375	12.615
Intermediate	14' - 2550'	12.25	9.675	8.755
Long-String	14' - 5850' 5850' - 7960'	8.5	7	6.276

#### **Class VI UIC Financial Responsibility Demonstration**

This submission is for:

Project ID: R09-CA-0010

Project Name: Mullen Storage Project

Current Project Phase: Pre-Injection Prior to Construction

#### **Cost Estimates**

Company providing estimates: California Resources Corp

Cost of each phase: Date of Third-Party Estimate:

Corrective Action on Deficient Wells: \$0.00 1/9/2022

Plugging Injection Well: \$0.00 1/9/2022

Post-Injection Site Care and Site Closure: \$0.00 1/9/2022 Emergency and Remedial Response: \$0.00 1/9/2022

Total Cost Estimate: \$.00
Year of Dollars: 2022

Cost Estimate File: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/FinancialResp-05-03-2022-

1838/Financial--Assurance--Cost--Estimation.pdf

1838/Primacy--Additional.pdf

#### **Trust Fund**

#### **Surety Bond**

#### **Letter of Credit**

Number of Letter of Credit Instruments: 1

#### Letter of Credit #1

Proof of Third Party Financial Strength

Using credit ratings to prove financial strength: Yes

Name of Issuing Institution: California Resources Corp

Credit Rating: B1 (stable)
Rating Date: 1/1/2022

Company Issuing Rating: Moody's

Phases Covered by Instrument:

Corrective Action on Deficient Wells

Plugging Injection Well

Post-Injection Site Care and Site Closure

Total Cost of Selected Phases: \$.00

Using more than one instrument to cover a single phase: No

Value of Instrument: \$0.00 Instrument Language

Standby Trust

Has a standby trust been established: No

Instrument File: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/FinancialResp-05-03-2022-

 $\underline{1838/Financial\text{--}Responsibility\text{--}Letter\text{--}of\text{--}Credit\text{--}CTV.pdf}$ 

#### **Third Party Insurance**

Number of Third Party Insurance Instruments: 1

#### Third Party Insurance #1

Proof of Third Party Financial Strength

Using credit ratings to prove financial strength: Yes

Name of Issuing Institution: California Resources Corp

Credit Rating: B1 (stable)

Rating Date: 1/1/2022

Company Issuing Rating: Moody's

Phases Covered by Instrument:

Emergency and Remedial Response

Total Cost of Selected Phases: \$.00

Using more than one instrument to cover a single phase: No

Value of Instrument: \$0.00
Instrument Language

Instrument File: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/FinancialResp-05-03-2022-

1838/Financial--Responsibility--Insurance.pdf

#### **Escrow Account**

#### **Self Insurance**

Is Self Insurance Used as a Financial Instrument: No

#### **Other Instrument**

#### **Notifications**

## **Complete Submission**

Authorized submission made by: Travis Hurst

For confirmation a read-only copy of your submission will be emailed to: travis.hurst@crc.com

#### CLASS VI FINANCIAL RESPONSIBILITY DEMONSTRATION

#### **COST ESTIMATES DESCRIPTION 40 CFR 146.85**

This financial assurance section for the project was prepared to meet the requirements §609.C.1 [40 CFR §146.82(a)(14) and §146.85(a)]. Carbon TerraVault Holdings (CTV) will provide updated estimates that are verified with a third party contractor. CTV utilized the EPA Cost Estimation Tool for initial estimates.

Financial responsibility will be covered by the following:

- 1. Letter of Credit for Post-Injection Site Care and Closure and Injection Well Plugging.
- 2. Insurance coverage for Emergency and Remedial Response.

The cost estimates for financial assurance are business confidential.

#### FINANCIAL RESPONSIBILITY

#### **CLASS VI EMERGENCY AND REMEDIAL RESPONSE INSURANCE**

#### 40 CFR 146.85

#### **Emergency and Remedial Response Insurance**

Carbon TerraVault Holding LLC (CTV) will provide financial assurance for Emergency and Remedial Response by procuring an environmental insurance policy. The limits will be re-determined by a reasonable estimate of the cost of these activities prior to the commencement of injection operations. The project environmental insurance policy will be placed with an A.M. Best A or higher rated carrier and will cover all emergency and remedial response activities arising from the assets. The selected insurance carrier will issue a financial assurance certificate in compliance with state and federal regulations.

#### FINANCIAL RESPONSIBILITY

#### **CLASS VI INJECTION WELL PLUGGING AND**

#### POST-INJECTION SITE CARE AND CLOSURE LETTER OF CREDIT

#### 40 CFR 146.85

#### **Project Letter of Credit Description**

Carbon TerraVault Holdings LLC (CTV) will provide financial assurance for Injection Well Plugging and Post-injection Site Care and Site Closure by posting a letter of credit. The amount of each letter of credit would be determined by a reasonable estimate of the cost of these activities. CTV will provide an updated estimate from a third party prior to project approval. The letter of credit will be backed by California Resources Corporation's (CRC) Credit Agreement with Citibank, N.A., as administrative agent, and certain other lenders as participants. This credit agreement consists of a senior revolving loan facility (Revolving Credit Facility) with an aggregate commitment of \$492 million, which CRC is permitted to increase if CRC obtains additional commitments from new or existing lenders. The Revolving Credit Facility also includes a sublimit of \$200 million for the issuance of letters of credit. The letters of credit were issued to support ordinary course marketing, insurance, regulatory and other matters. As of June 30, 2021, CRC had an undrawn Revolving Credit Facility, approximately \$75 million available in letter of credit issuance capacity and \$151 million of cash. CRC is currently making efforts to add to the aggregate commitment and the sub-limit for letters of credit.

## **Financial Responsibility**

No additional cost information necessary.

#### **Class VI UIC Pre-Operational Testing**

This submission is for:

Project ID: R09-CA-0010

Project Name: Mullen Storage Project

Current Project Phase: Pre-Injection Prior to Construction

2022-1838/Preoperational--Formation--Testing--CTV--III.pdf

Proposed Pre-Operational Testing Schedule: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-

PreConstruction/PreOpTest-05-03-2022-1838/Pre-operational--Formation--Testing--CTV--III.pdf

2022-1838/EPA--Primacy--Pre-Operational--Testing.pdf

## **Well and Cement Logs**

**MITs** 

**Core Analyses** 

#### **Formation Characterization**

## **Injection Well Testing**

## **Complete Submission**

Authorized submission made by: Travis Hurst

For confirmation a read-only copy of your submission will be emailed to: travis.hurst@crc.com

The EPA has primacy in the state of California. Additional pre-operational testing not required.

#### **PREOPERATIONAL TESTING**

#### CTV III

## **Preoperational Testing**

#### Overview

Pre-operational formation testing for the project includes a suite of logging, coring, geohydrologic testing and reservoir testing during the drilling and completion of the injection and monitoring wells.

- 1. Open-hole logging will support reservoir rock and fluid properties characterization.
- 2. Coring of the reservoir and confining layer will provide data on porosity, permeability, mineralogy, and lithology.
- 3. Fluid sampling, pressure and temperature data gathering will define project baselines.
- 4. Reservoir testing will assess reservoir and confining layer geomechanics.

The results of the testing activities will be documented in a report and submitted to the EPA after the well drilling and testing activities have been completed, and before carbon dioxide injection commences.

For injection and monitoring wells see Attachment G for pre-injection testing of project wells.

Preoperational testing schedule will be discussed with the EPA during site review and testing will be completed prior to the injection of CO<sub>2</sub>.

#### 1. Reservoir

Reservoir property data will define the USDW, monitoring zone and storage reservoir baselines for monitoring. The stresses will constrain the operating parameters. One representative sample or test will be performed for each of the following:

- Pressure, temperature, and fluid samples of the storage reservoir, monitoring zone and USDW.
  - Fluid sampling for all analytes to be monitored during injection operations, per the Testing and Monitoring Plan
- Step rate test of the storage reservoir and confining zone to define fracture gradients.
- Perform pressure build-up testing as part of the Pre-Operational Testing plan (anticipated testing method: pressure build-up test).

#### 2. Wireline Logging Program

Wireline logging of new injection wells and monitoring wells will consist of conventional and advanced open-hole and cased-hole logs of the surface, intermediate, and injection sections.

Open-hole logging program:

- Triple combo (gamma ray, neutron porosity, bulk density, resistivity) will be run on the surface, intermediate and injection intervals for all injection and monitoring wells.
- Advanced logs like Spectral gamma ray, dipole full-wave sonic and nuclear magnetic resonance (NMR)
  logs will be run over the intermediate and injection intervals for one of the injection or monitoring
  wells.

#### Cased-hole logging program:

- Cement bond logs will be run on the surface, intermediate and injection casing sections to verify cement integrity and zonal isolation.
- A pulsed neutron capture log should be run on the injection zone to provide a baseline water-to-gas saturation to support saturation and injection modeling over the life of the project.

#### 3. Coring Program

A whole core / sidewall core will be taken on one well to evaluate fluid and rock properties to calibrate against open-hole logs. The objective of the coring zones is to determine the nature of the storage reservoir and the confining layer properties.

#### Proposed Core Analyses for the Confining Layer and Storage Reservoir:

- Porosity
- Permeability to air
- Saturations
- Grain density to calibrate porosity logs
- Core descriptions

#### **Proposed Special Core Analysis:**

- Capillary pressure on select plugs to determine pore throats and relate water saturations to permeability (K) and porosity (φ) for the storage reservoir and confining layer
- X-ray diffraction (XRD) to determine clay mineralogy and validate petrophysical clay volume calculations for the storage reservoir and confining layer
- CO2 to water relative permeability for the storage reservoir
- Thin section and scanning electron microscopy (SEM) analyses for the confining later and storage reservoir

#### 4. CO2 Stream Compatibility with Subsurface Fluids, Minerals and Materials

- Confirm the composition and water content of the CO2 injectate as part of baseline sampling and verify that it will not react with the formation matrix (anticipated testing methods: various geochemical analyses).
- Confirm that the properties of the CO2 stream are consistent with the AoR delineation model inputs (anticipated testing methods: various geochemical analyses).

- Confirm that the analytes for injectate and ground water quality monitoring are appropriate based on the results of geochemical modeling evaluation (anticipated testing methods: various geochemical analyses).
- Following the pre-construction measurement of the composition, properties, and corrosiveness of the injectate, review the well construction materials and cement in the context of the results of these tests (anticipated testing methods: various geochemical analyses).

## 5. Seismic History and Seismic Risk

Provide a seismicity monitoring plan and establish baseline seismicity (anticipated testing method: existing seismic network/historic seismicity database).

## 6. Financial Responsibility

Updated cost estimates based on third party assessment and confirmation of insurance and credit line.

## 7. <u>Alternative PISC Timing Determination</u>

Acquisition of data gathered as part of preoperational testing will aid in refining plume stability in support of alternative PISC timing.

#### **PREOPERATIONAL TESTING**

#### CTV III

## **Preoperational Testing**

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- Porosity
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- Capillary pressure on select plugs to determine pore throats and relate water saturations to permeability (K) and porosity (φ) for the storage reservoir and confining layer
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Provide a seismicity monitoring plan and establish baseline seismicity (anticipated testing method: existing seismic network/historic seismicity database).

## 6. Financial Responsibility

Updated cost estimates based on third party assessment and confirmation of insurance and credit line.

## 7. <u>Alternative PISC Timing Determination</u>

Acquisition of data gathered as part of preoperational testing will aid in refining plume stability in support of alternative PISC timing.

#### **Class VI UIC Project Information Tracking**

This submission is for:

Project ID: R09-CA-0010

Project Name: Mullen Storage Project

Current Project Phase: Pre-Injection Prior to Construction

#### **General Information**

Number of proposed Class VI wells: 6

Brief description of the project: Six Class VI injection wells.

Underground Injection Control (UIC) Program under Safe Drinking Water Act (SDWA)

Description: Class VI application for carbon storage

Optional Additional Project Information

The Wild and Scenic Rivers Act, 16 U.S.C. 1273 et seq.

https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/ProjInfo-05-03-2022-1838/Federal--Laws--CTV--

III.pdf

#### **Facility and Owner/ Operator Information**

Facility name: Carbon Terra Vault III

Facility mailing address: 4809 Elk Hills Rd, Tupman, CA 93276 Facility location: Latitude: 35.278 Longitude: -119.469

Up to four Standard Industrial Classification (SIC) codes for the products/services provided by the facility: 7389

Facility located on Indian lands: No

Facility contact information

Contact person: William Chessum

Contact's business phone number: 562 - 508 - 5781 Contact's business email: william.chessum@crc.com Operator's name: Carbon TerraVault Holdings LLC

Operator's business address: 27200 Tourney Road, Suite 200 Santa Clarita, CA 91355

Operator's business phone number: 888 - 848 - 4754

Operator's status: Private
Ownership status: Owner

#### **Initial Permit Application**

Permit Application Narrative: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/ProjInfo-05-03-2022-

1838/Attachment--A-----CTV--III-----Narrative.pdf

Proposed project plans, submitted with the Project Plan Submission module:

An Area of Review (AoR) and Corrective Action Plan

A Testing and Monitoring Plan

A Well Plugging Plan

A Post-Injection Site Care (PISC) and Site Closure Plan

An Emergency and Remedial Response Plan

Computational modeling information, submitted with the Area of Review Computational Modeling module

A financial responsibility demonstration, submitted with the Financial Responsibility Demonstration module

A proposed pre-operational logging and testing program, submitted with the Pre-Operational Testing module

 $\underline{1838/Attachment--G----CTV--III-----Well--Construction--and--Testing--and--Operating.zip}$ 

### **Updated Information**

#### **Complete Submission**

Authorized submission made by: Travis Hurst

For confirmation a read-only copy of your submission will be emailed to: travis.hurst@crc.com

#### ATTACHMENT G: WELL CONSTRUCTION AND TESTING

#### CTV III

#### **Facility Information**

Facility Name: CTV III

Facility Contact: William Chessum / Technical Manager

(562) 999-8380 / William.chessum@crc.com

Location:

#### **Introduction**

New injection wells C1, C2, E1, E2, W1, and W2 are planned and designed specifically for CO₂ sequestration purposes. These wells will target selective intervals within the injection zone to optimize plume development and injection conformance. Additionally, three new monitoring wells are required to support the storage project. M1 and M2 will be injection zone monitoring wells, and D1 will be an abovezone monitoring well. Two USDW monitoring wells, US1 and US2, will also be constructed prior to injection. Figure 1 shows the location of the new wells.



All planned new wells will be constructed with components that are compatible with the injectate and formation fluids encountered such that corrosion rates and cumulative corrosion over the duration of the project are acceptable. The proposed well materials will be confirmed based on actual CO<sub>2</sub> composition such that material strength is sufficient to withstand all loads encountered throughout the life of the well with an acceptable safety factor incorporated into the design. Casing points will be verified by trained geologists using real-time drilling data such as LWD and mud logs to ensure non-endangerment of USDW. Due to the depth of the base of USDW, an intermediate casing string will be utilized to isolate the USDW. Cementing design, additives, and placement procedures will be sufficient to ensure isolation of the injection zone and protection of USDW using cementing materials that are compatible with injectate, formation fluids, and subsurface pressure and temperature conditions.

Appendix C-1: Injection and Monitoring Well Schematics provides casing diagram figures for all injection and monitoring wells with construction specifications and anticipated completion details in graphical and/or tabular format.

Injection wells will have wellhead equipment sufficient to shut off injection at surface. The project does not anticipate risk factors that warrant downhole shut-off devices, such as high temperature, high pressure, presence of hydrogen sulfide, proximity to populated areas, or high likelihood of damage to the wellhead.

### Proposed Stimulation Program [40 CFR 146.82(a)(9)]

No stimulation program is proposed at this time.

### Well Construction Procedures [40 CFR 146.82(a)(12)]

Injection and monitoring wells will be drilled during pre-operational testing, and no abnormal drilling and completion challenges are anticipated. The drilling histories of nearby wells provide key information to drilling professionals and identify the expected conditions to be encountered. The wells will be constructed with objectives to achieve target CO<sub>2</sub> injection rates, to prevent migration of fluids out of the the shallow formations, and to allow for monitoring, as described

by the following:

- Well designs will be sufficient to withstand all anticipated load cases including safety factors.
- Multiple cemented casing strings will protect shallow USDW-bearing zones from contacting injection fluid.
- All casing strings will be cemented in place with volume sufficient to place cement to surface using industry-proven recommended practices for slurry design and placement
- Cement bond logging (CBL) will be used to verify presence of cement in the production casing annulus through and above the confining layer.
- Mechanical integrity testing (MIT) will be performed on the tubing and the tubing/casing annulus.
- Upper completion design enables monitoring devices to be installed downhole, cased hole logs to be acquired and MIT to be conducted.

- All wellhead equipment and downhole tubulars will be designed to accommodate the dimensions necessary for deployment of monitoring equipment such as wireline-conveyed logging tools and sampling devices.
- Realtime surface monitoring equipment with remote connectivity to a centralized facility and alarms provides continual awareness to potential anomalous injection conditions
- Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment

Well materials utilized will be compatible with the CO<sub>2</sub> injectate and will limit corrosion.

- Wellhead stainless steel or other corrosion resistant alloy
- Casing 13Cr L-80 or other corrosion resistant alloy in specified sections of production string (ie. flow-wetted casing)
- Cement Portland cement has been used extensively in enhanced oil recovery (EOR) injectors.
   Data acquired from existing wells supports that the materials are compatible with CO₂ where good cement bond between formation and casing exists.
- Tubing 13Cr L-80 or other corrosion resistant alloy
- Packer corrosion resistant alloy and hardened elastomer

Well materials follow the following standards:

- API Spec 6/CT ISO 11960 Specifications for Casing and Tubing
- API Spec 10A/ISO 10426-1 Specifications for Cements and Materials for Cementing
- API Spec 11D1/ISO 14310 Downhole Equipment Packers and Bridge Plugs

### Casing and Cementing

Well-specific casing diagrams including casing specifications are presented in Appendix C-1: Injection and Monitoring Well Schematics to meet the requirements of 40 CFR 146.86(b)(1)(iv). These specifications allow for the safe operation at bottomhole injection conditions not to exceed the maximum allowable operating pressure (MAOP) of 0.684 psi/ft specified in the Appendix: Operating Procedures.

These conditions are not extreme, and standard cementing and casing best practices are sufficient to ensure successful placement and isolation. Industry standard practices and procedures for designing and placing primary cement in the casing annuli will be utilized to ensure mechanical integrity of cement and casing. Staged cementing is not an anticipated requirement.

Operational parameters acquired throughout the pressure pumping operation will be used to compare modeled versus actual pressure and rate. The presence of circulated cement at surface will also be a primary indicator of effective cement placement. Cement evaluation logging will be conducted to confirm cement placement and isolation.

#### **Tubing and Packer**

The information in the tables provided in Appendix C-1: Injection and Monitoring Well Schematics is representative of completion equipment that will be used and meets the requirements at 40 CFR 146.86(c). Tubing and packer selection and specifications will be determined after well construction is completed during pre-operational testing.

### <u>Pre-Injection Testing Plan – Injection Wells</u>

The following tests and logs will be acquired during drilling, casing installation and after casing installation in accordance with the testing required under 40 CFR 146.87(a), (b), (c), and (d). The testing activities described in this attachment are restricted to the pre-injection phase. Testing and monitoring activities during the injection and post-injection phases are described in Attachment C.

#### **Deviation Checks**

Deviation measurements will be conducted approximately every 120' during construction of the well.

### **Tests and Logs**

The following logs will be acquired during the drilling or prior to the completion of the C1, C2, E1, E2, W1, and W2 wells:

- Dual Induction Laterolog
- Spontaneous Potential
- Gamma Ray
- Caliper
- Compensated Neutron
- Formation Density
- Mud Log
- Acoustic Cement Bond Log

# **Demonstration of Mechanical Integrity**

Below is a summary of the tests to be performed prior to CO<sub>2</sub> injection:

Class VI Rule Citation	Rule Description	Test Description	Program Period
40 CFR 146.89(a)(1)	MIT - Internal	SAPT	Prior to operation
40 CFR 146.87(a)(4)	MIT - External	Temperature Log	Prior to operation

### **Annulus Pressure Test Procedures**

- 1. The tubing/casing annulus (annulus) will be filled with liquid. The volume of fluid required will be measured.
- 2. Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test.

- 3. After stabilization, the annulus of the well will be pressurized to a surface pressure of no less equal to or greater than the highest annular pressure specified in the Operating Procedures document. Following pressurization, the annular system must be isolated from the source (annulus tank) by a closed valve.
- 4. The annulus system must remain isolated for a period of no less than 60 minutes. During the period of isolation, measurements of pressure will be made at ten-minute intervals. The annulus system must remain isolated for a period of no less than 60 minutes. During the period of isolation, measurements of pressure will be made at ten-minute intervals.

CTV will notify the EPA at least 30 days prior to conducting the test and provide a detailed description of the testing procedure. Notification and the opportunity to witness these tests/logs shall be provided to EPA at least 48 hours in advance of a given test/log.

### Injectivity and Pressure Fall-Off Testing for Injection Wells

Injectivity testing using brine compatible with formation fluids and formation mineralogy will provide assurance of wellbore connectivity with the reservoir and can be used to forecast  $CO_2$  injection rate. The benefit of completing a pressure fall-off test is to assess injectivity, reservoir flow boundary distances and reservoir pressures. CTV will complete injectivity and pressure fall off testing prior to  $CO_2$  injection, pursuant to 40 CFR §146.87(e).

CTV will consider pressure fall-off testing throughout the injection phase to complement reservoir monitoring if injection rate decreases along with a simultaneous injection pressure increase outside the results from computational modeling.

Pressure fall-off testing procedures are described below:

- 1. Injection rate will be held constant prior to shut in. The injection rate will be high enough to produce a pressure buildup that will result in valid test data. The maximum operating pressure will not be exceeded.
- 2. Upon shutting in the injector, surface and bottom-hole pressure and temperature measurements will be taken continuously. If there are offset injectors, rates will be held constant and recorded during the test.
- 3. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage or skin.

A surface gauge at the wellhead and a downhole gauge set above the packer with real-time surface readout capability will be used for the pressure falloff test. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy.

# <u>Pre-Injection Testing Plan – Monitoring Wells M1 and M2</u>

Monitoring wells proposed for the CTV storage project will be drilled prior to CO<sub>2</sub> injection. CTV will install monitoring equipment and ensure well integrity in the well construction and completion process. The

testing activities described in this attachment are restricted to the pre-injection phase. Testing and monitoring activities during the injection and post-injection phases are described in Attachment C.

#### **Deviation Checks**

Deviation measurements for M1 and M2 will be recorded approximately every 120' for each well during construction of the well.

### **Tests and Logs**

The following logs will be acquired during the drilling and prior to the completion of these wells:

- Dual Induction Laterolog
- Spontaneous Potential
- Gamma Ray
- Caliper
- Compensated Neutron
- Formation Density
- Acoustic Cement Bond Log

### **Demonstration of Mechanical Integrity**

CTV will run mechanical integrity logs and tests prior to CO<sub>2</sub> injection operations.

#### Annulus Pressure Test Procedures

- The tubing/casing annulus (annulus) will be filled with liquid. The volume of fluid required will be measured.
- 2. Temperature stabilization of the well and annulus liquid will be verified prior to conducting the test.
- 3. The annulus of the well will be pressurized to a surface pressure of no less than 500 PSI. Following pressurization, the annular system will be isolated from the source (annulus tank) by a closed valve.
- 4. The annulus system must remain isolated for a period of no less than 60 minutes. During the period of isolation, measurements of pressure will be made at ten-minute intervals.

### Pre-Injection Testing Plan - USDW Monitoring Wells:

USDW monitoring wells proposed for the CTV storage project will be drilled prior to CO<sub>2</sub> injection. CTV will ensure well integrity in the well construction and completion process. The testing activities described in this attachment are restricted to the pre-injection phase. Testing and monitoring activities during the injection and post-injection phases are described in Attachment C.

#### **Deviation Checks**

Deviation measurements will be recorded approximately every 120' for each well during construction of the well

# **Tests and Logs**

The following logs will be acquired during the drilling and prior to the completion of these wells:

- Dual Induction Laterolog
- Spontaneous Potential
- Gamma Ray
- Caliper
- Compensated Neutron
- Formation Density
- Acoustic Cement Bond Log

# Demonstration of mechanical integrity

CTV will pressure test the casing before perforating and baseline sampling, prior to CO<sub>2</sub> injection operations.

# Carbon TerraVault III Class VI Permit Application Narrative Report

# 4-25-2022

Submitted to: U.S. Environmental Protection Agency Region 9 San Francisco, CA

# Prepared by:



27200 Tourney Road, Suite 200 Santa Clarita, CA 91355 (888) 848-4754

# **Table of Contents**

1.0 Project Background and Contact Information	1
2.0 Site Characterization	3
2.1 Regional Geology, Hydrogeology, and Local Structural Geology [40 CFR 146.82(a)(3)(vi)]	3
2.1.1 Geologic History	3
2.1.2 Site Geology Overview	4
2.1.3 Geological Sequence	9
2.2 Maps and Cross Sections of the AoR [40 CFR 146.82(a)(2), 146.82(a)(3)(i)]	11
2.2.1 Data	11
2.2.Site Stratigraphy	15
2.2.3 Map of the Area of Review	18
2.3 Faults and Fractures [40 CFR 146.82(a)(3)(ii)]	19
2.3.1 Overview	20
2.4 Injection and Confining Zone Details [40 CFR 146.82(a)(3)(iii)]	23
2.4.1 Mineralogy	23
2.4.2 Porosity and Permeability	24
2.4.3 Confining Zone Capillary Pressure	30
2.4.4 Depth and Thickness	30
2.4.5 Structure Maps	31
2.4.6 Isopach Maps	31
2.5 Geomechanical and Petrophysical Information [40 CFR 146.82(a)(3)(iv)]	31
2.5.1 Caprock Ductility	32
2.5.2 Stress Field	33
2.6 Seismic History [40 CFR 146.82(a)(3)(v)]	37
2.7 Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]	41
2.7.1 Hydrologic Information	42
2.7.2 Base of Fresh Water and Base of USDWs	43
2.7.3 Formations with USDWs	45
2.7.4 Geologic Cross Sections Illustrating Formations with USDWs	47
2.7.5 Principal Aquifers	49
2.7.6 Potentiometric Maps	50
2.7.7 Water Supply Wells	54
2.8 Geochemistry [40 CFR 146.82(a)(6)]	55
2.8.1 Formation Geochemistry	55

2.8.2 Fluid Geochemistry	55
2.8.3 Fluid-Rock Reactions	57
2.9 Other Information	57
2.10 Site Suitability	57
3.0 AoR and Corrective Action	58
4.0 Financial Responsibility	59
5.0 Injection and Monitoring Well Construction	59
5.1 Proposed Stimulation Program	59
5.2 Construction Procedures	59
5.2.1 Casing and Cementing	60
6.0 Pre-Operational Logging and Testing	61
7.0 Well Operation	61
7.1 Operational Procedures	61
7.1.1 Annulus Pressure	62
7.1.2 Maximum Injection Rate	63
7.1.3 Shutdown Procedures	63
7.2 Proposed Carbon Dioxide Stream	63
8.0 Testing and Monitoring	64
9.0 Injection Well Plugging	64
10.0 Post-Injection Site Care (PISC) and Site Closure	64
11.0 Emergency and Remedial Response	65
12.0 Injection Depth Waiver and Aquifer Exemption Expansion	65
13.0 Reference	65

# ATTACHMENT A: CLASS VI PERMIT APPLICATION NARRATIVE 40 CFR 146.82(a)

#### Carbon TerraVault III

### 1.0 Project Background and Contact Information

Carbon TerraVault Holdings LLC (CTV), a wholly owned subsidiary of California Resources Corporation (CRC), proposes to construct and operate six CO<sub>2</sub> geologic sequestration wells at the project area located in San Joaquin County, California. This application was prepared in accordance with the U.S. Environmental Protection Agency's (EPA's) Class VI, in Title 40 of the Code of Federal Regulations (40 CFR 146.81). CTV is not requesting an injection depth waiver or aguifer exemption expansion.

CTV forecasts the potential CO<sub>2</sub> stored in the at million tonnes annually for years. CO<sub>2</sub> will be sourced from direct air capture and other CO<sub>2</sub> sources in the project area.

The Carbon TerraVault III (CTV III) storage site is located in the Sacramento Valley,

The project will consist of six injectors, surface facilities, and monitoring wells. This supporting documentation applies to the six injection wells.

CTV will actively communicate project details and submitted regulatory documents to County and State agencies:

- Geologic Energy Management Division (CalGEM)
   District Deputy
   Mark Ghann-Amoah: (661) 322-4031
- CA Assembly District 13
   Assemblyman Carlos Villapudua
   31 East Channel Street Suite 306
   Stockton, CA 95202
   (209) 948-7479
- San Joaquin County
   District 3 Supervisor –Tom Patti
   (209) 468-3113
   tpatti@sigov.org
- San Joaquin County Community Development Director – David Kwong 1810 East Hazelton Avenue Stockton, CA 95205 (209) 468-3121

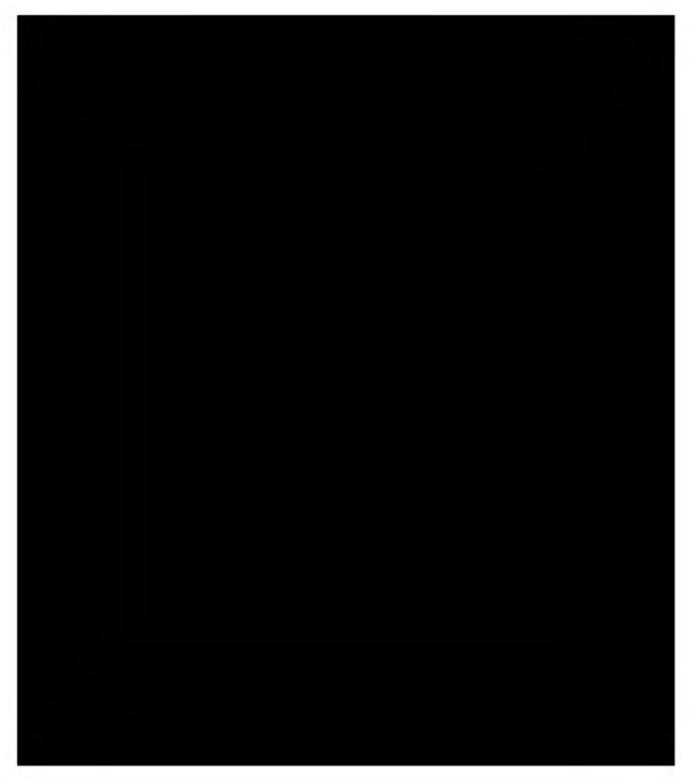
- 5. San Joaquin Council of Governments Executive Director – Diane Nguyen 555 East Weber Avenue Stockton, CA 95202 (209) 235-0600
- 6. Region 9 Environmental Protection Agency 75 Hawthorne Street San Francisco, CA 94105 (415) 947-8000

# 2.0 Site Characterization

2.1 Regional Geology, Hydrogeology, and Local Structural Geology [40 CFR 146.82(a)(3)(vi)]

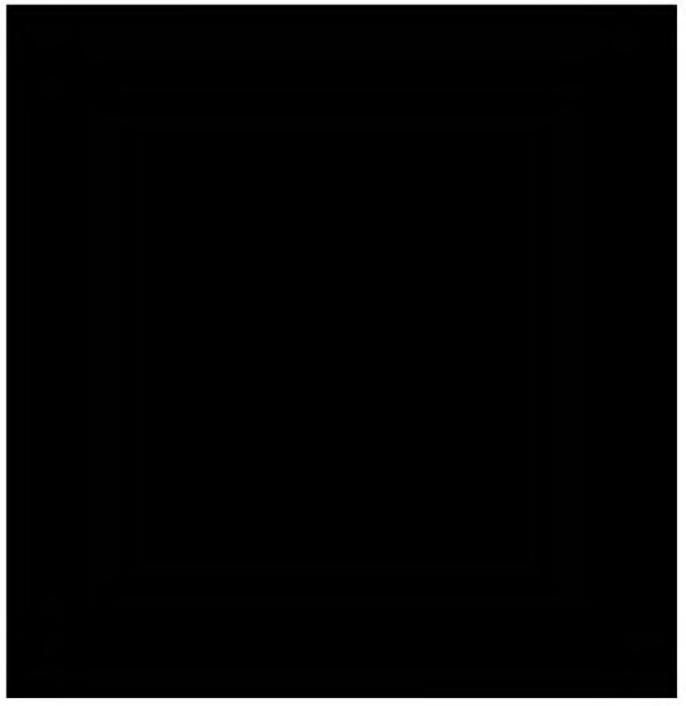
# 2.1.1 Geologic History

The CTV III storage site is located	



# 2.1.2 Site Geology Overview

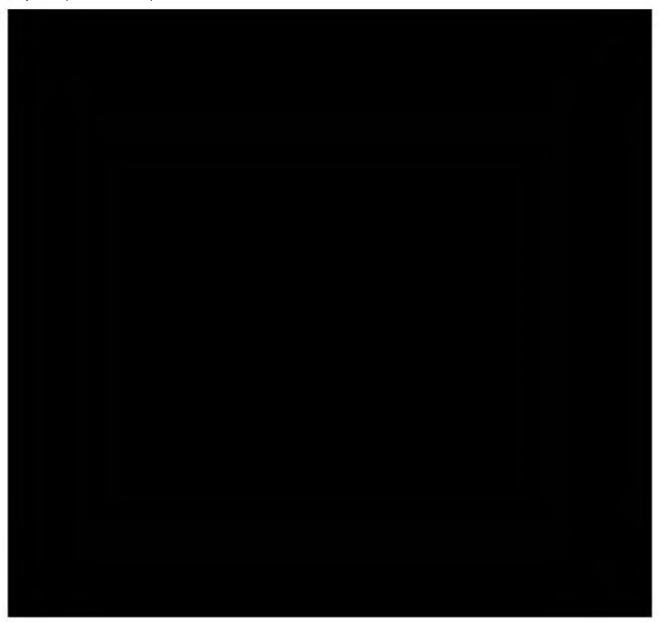
The CTV III project area lies within the Sacramento Basin in northern California (**Figure 2.1-2**). The Sacramento Basin is the northern, asymmetric sub-basin of the larger, Great Valley Forearc. This portion of the basin, that contains a steep western flank and a broad, shallow eastern flank, spans approximately 240 miles in length and 60 miles wide (Magoon 1995).



# 2.1.2.1 Basin Structure

The Great Valley was developed during mid to late Mesozoic time. The advent of this development occurred under convergent-margin conditions via eastward, Farallon Plate subduction, of oceanic crust beneath the western edge of North America (Beyer 1988). The convergent, continental margin, that characterized central California during the Late Jurassic through Oligocene time, was later replaced by a transform-margin tectonic system. This occurred as a result of the northward migration of the Mendocino Triple Junction (from Baja California to its present location off the coast of Oregon), located along California's coast (Figure 2.1-3). Following this migrational event was the progressive cessation of both subduction and arc volcanism as the progradation of a transform fault system moved in as the primary tectonic environment (Graham 1984). The major current day fault, the San Andreas, intersects most of

the Franciscan subduction complex, which consists of the exterior region of the extinct convergent-margin system (Graham 1984).

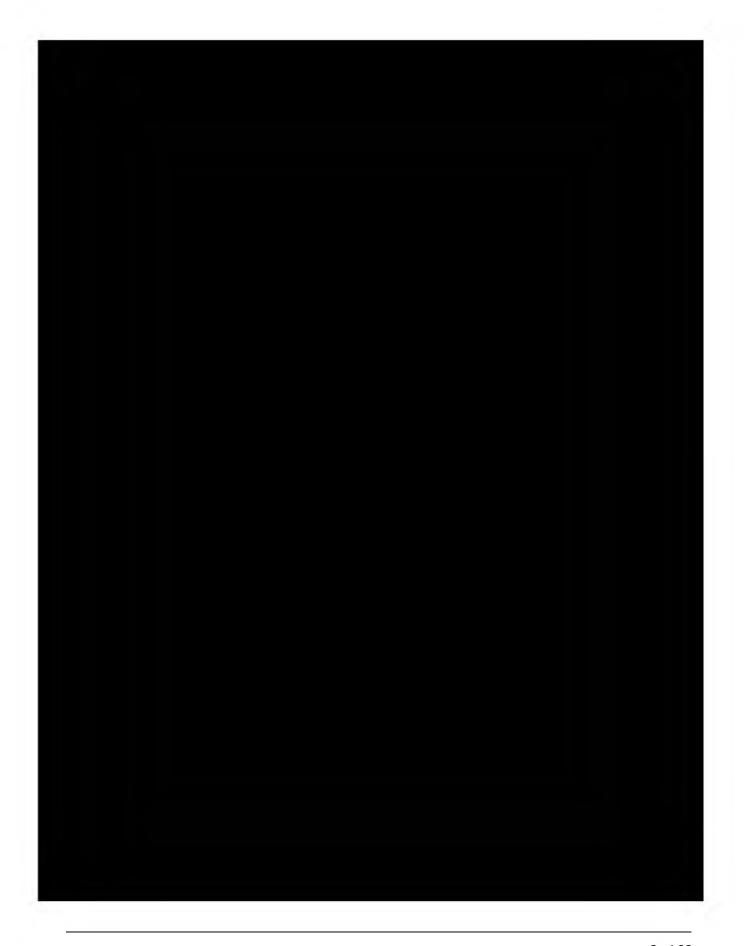


### 2.1.2.2 Basin Stratigraphy

The structural trough that developed subsequent to these tectonic events, that became named the Great Valley, became a depocenter for eroded sediment and thereby currently contains a thick infilled sequence of sedimentary rocks. These sedimentary formations range in age from Jurassic to Holocene. The first deposits occurred as an ancient seaway and through time were built up by the erosion of the surrounding structures. The basin is constrained on the west by the Coast Range Thrust, on the north by the Klamath Mountains, on the east by the Cascade Range and Sierra Nevada and the south by the Stockton Arch Fault (Figure 2.1-2). To the west the Coastal Range boundary was created by uplifted rocks of the Franciscan Assemblage (Figure 2.1-4). The Sierra Nevadas, that make up the eastern boundary, are a result of a chain of ancient volcanos.



Basin development is broken out into evolutionary stages at the end of each time-period of the arc-trench system, from Jurassic to Neogene, in **Figure 2.1-5**. As previously stated, sediment infill began as an ancient seaway and was later sourced from the erosion of the surrounding structures. Sedimentary infill consists of Cretaceous-Paleogene fluvial, deltaic, shelf and slope sediments. Due to the southward tilt of the basin



This area is a minor structural trap with a slight dip of about 2.8 degrees to the west leaving the area mostly flat.



2.1.3 Geological Sequence

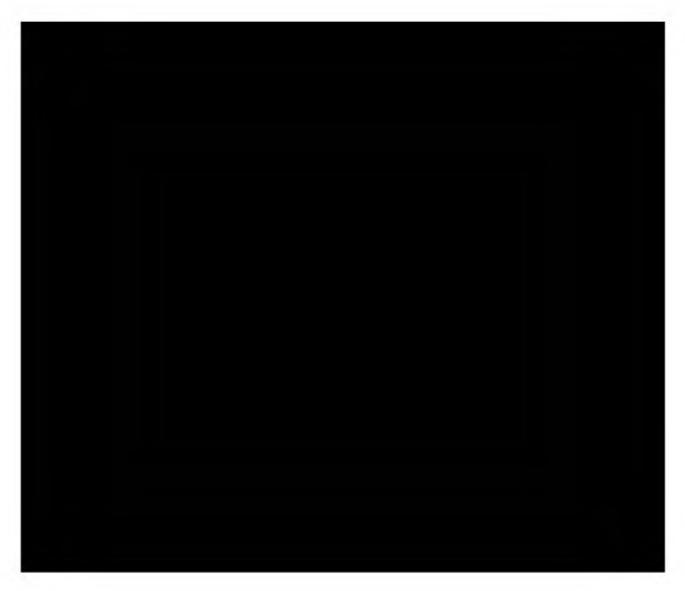
The injection zone is shown in red as the

The average injection depth is approximately

TVDSS.



Following its deposition, the was buried under the which carries throughout most of its distribution. This formation serves as the upper confining zone for the reservoir due to its low permeability, thickness, and regional continuity that spans beyond the AoR (Figure 2.1-7). Above the sis the and since the reservoir due to its low permeability, thickness, and regional continuity that spans beyond the AoR (Figure 2.1-7).



# 2.2 Maps and Cross Sections of the AoR [40 CFR 146.82(a)(2), 146.82(a)(3)(i)]

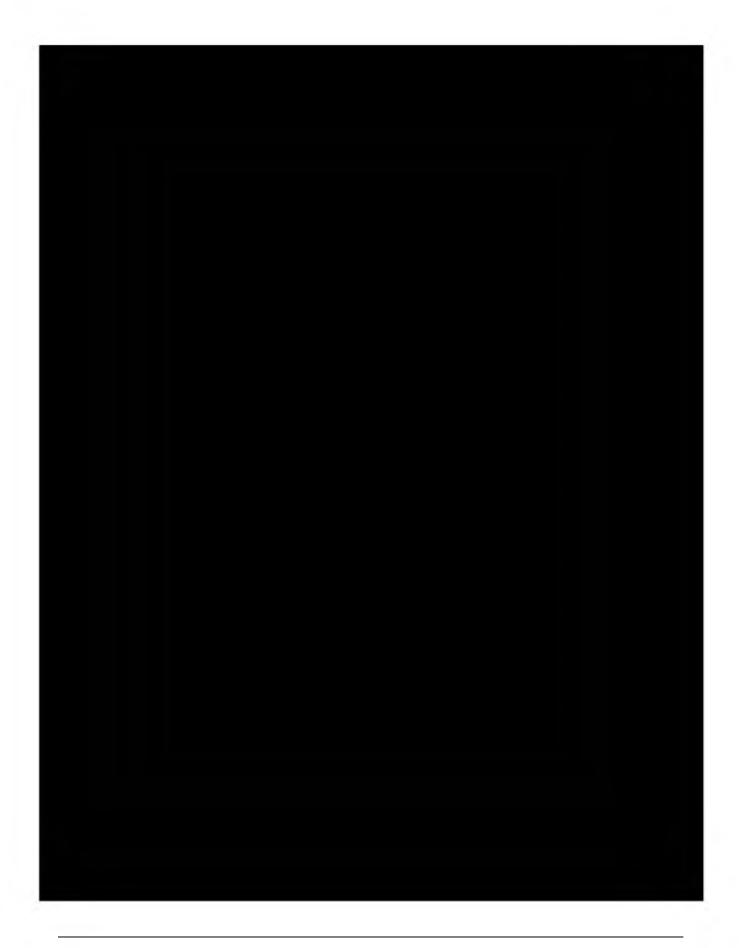
# 2.2.1 Data

To date, 46 wells have been drilled to various depths within the project AoR. Along with an extensive database of wells in this field, seismic coverage, core and reservoir performance data such as production and pressure give an adequate description of the reservoir (**Figure 2.2-1**).



Well data are used in conjunction with three-dimensional (3D) and two-dimensional (2D) seismic to define the structure and stratigraphy of the injection zone and confining layers (Figure 2.2-2). Figure 2.2-3 shows outlines of the seismic data used and the area of the structural framework that was built from these seismic surveys. The 3D data in this area were merged using industry standard pre-stack time migration in 2013, allowing for a seamless interpretation across the seismic datasets. The 2D data used for this model were tied to this 3D merge in both phase and time to create a standardized datum for mapping purposes. The following layers were mapped across the 2D and 3D data:

- A shallow marker to aid in controlling the structure of the velocity field
- The approximate base of the strata below which is unconformable with the Eocene strata below
- •
- •





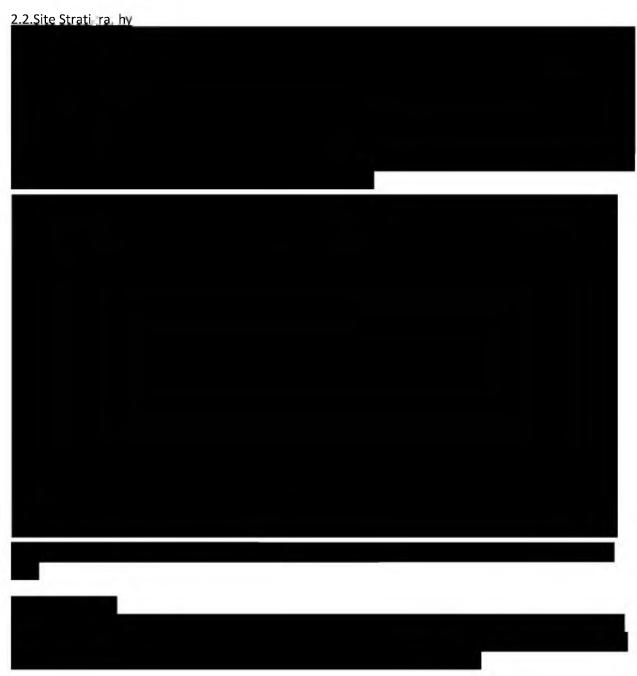
The top of the was used as the base of this structural model due to the depth and imaging of Basement not being sufficient to create a reliable and accurate surface. Interpretation of these layers began with a series of well ties at well locations shown in **Figure 2.2-3**. These well ties create an accurate relationship between wells which are in depth and the seismic which is in time. The layers listed above were then mapped in time and gridded on a 550 by 550 foot cell basis. Alongside this mapping was the interpretation of any faulting in the area which is discussed further in the Faults and Fracture section of this document.

The gridded time maps and a sub-set of the highest quality well ties and associated velocity data are then used to create a 3D velocity model. This model is guided between well control by the time horizons and is iterated to create an accurate and smooth function. The velocity model is used to convert both the gridded time horizons and interpreted faults into the depth domain. The result is a series of depth grids of the layers listed above which are then used in the next step of this process.

The depth horizons are the basis of a framework which uses conformance relationships to create a series of depth grids that are controlled by formation well tops picked on well logs. The grids are used as structural control between these well tops to incorporate the detailed mapping of the seismic data. These grids incorporate the thickness of zones from well control and the formation strike, dip, and any fault offset from the seismic interpretation. The framework is set up to create the following depth grids for input in to the geologic and plume growth models:

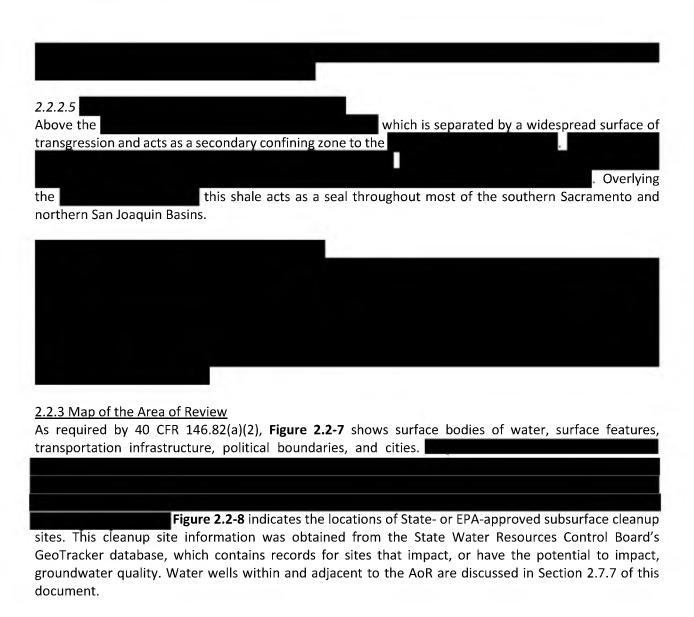
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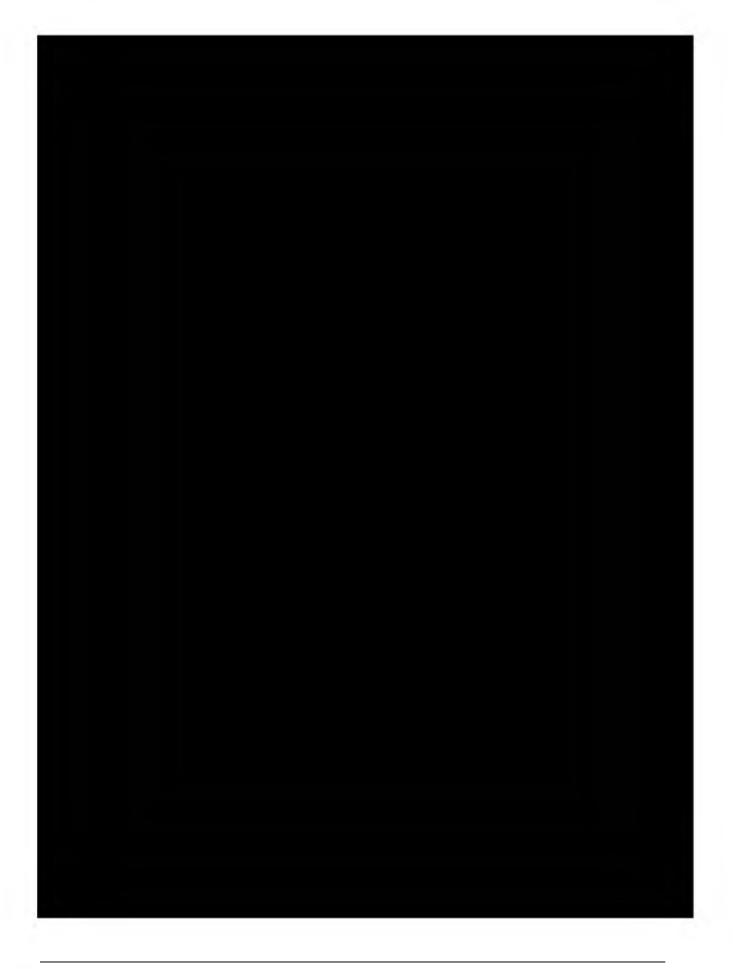












# 2.3 Faults and Fractures [40 CFR 146.82(a)(3)(ii)]

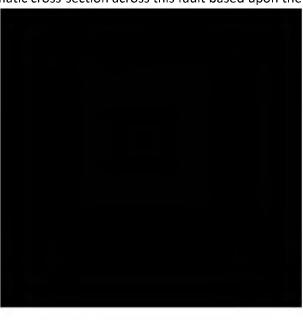
# 2.3.1 Overview

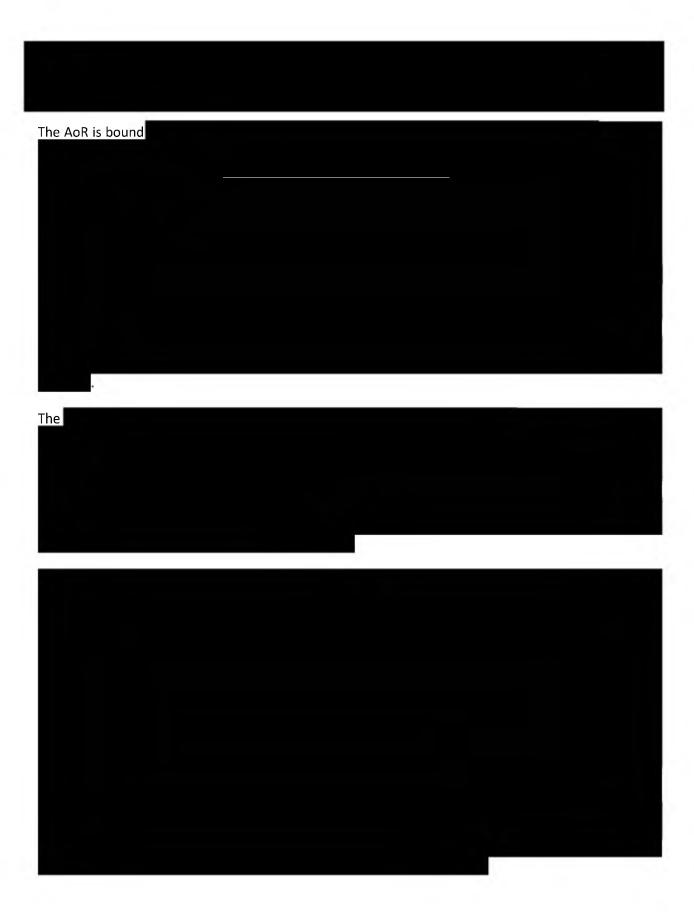
A combination of 3D and 2D seismic, along with well control, were used to define faulting within the area (Figure 2.2-3).

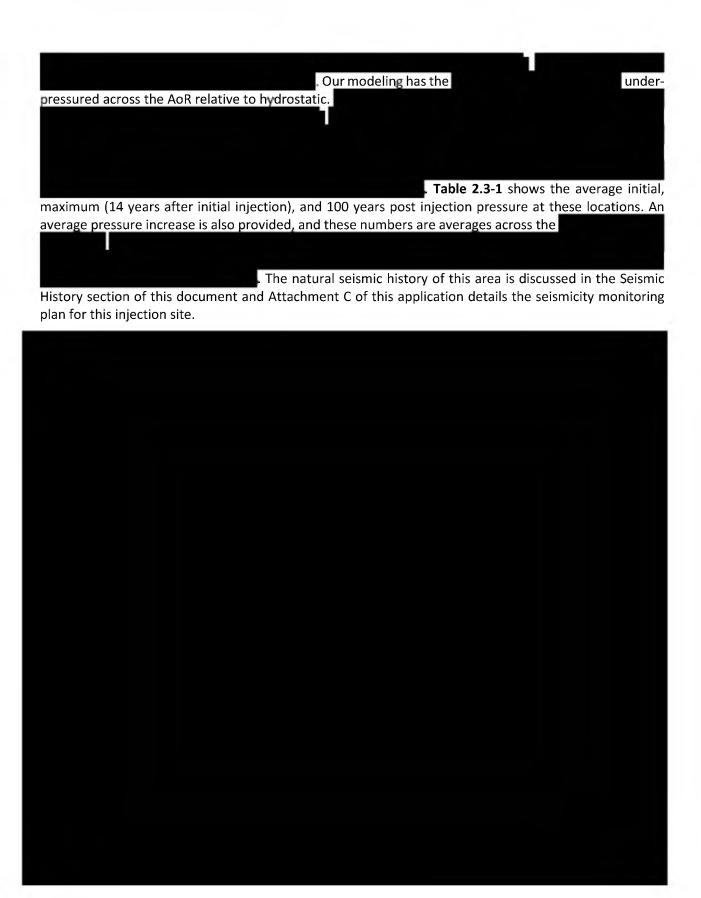
Our geologic model shows an average thickness within the CO<sub>2</sub> plume boundary to be 210 ft.

As discussed in the Injection and Confining Zone Details section, mineralogy data will be collected for the but based on data from the we expect the to be clay rich and therefore continue to provide a vertical seal to the above the will be monitored as part of the monitoring and testing plan.

Figure 2.3-2 shows a schematic cross-section across this fault based upon the seismic interpretation.









# 2.4 Injection and Confining Zone Details [40 CFR 146.82(a)(3)(iii)]

# 2.4.1 Mineralogy

No quantitative mineralogy information exists within the AoR boundary. Mineralogy data will be acquired across all the zones of interest as part of pre-operational testing. Several wells outside the AoR have mineralogy over the respective formations of interest, and that data is presented below.

2.4.1.1

The well outside the AoR has x-ray diffraction (XRD) data for the (see **Figure 2.4-1** for well locations). Reservoir sand from four samples within this well averages 33% quartz, 42% plagioclase and potassium feldspar, and 24% total clay (see **Table 2.4-1**). The primary clay minerals are kaolinite and mixed layer illite/smectite. Calcite & dolomite were not detected in any of the samples.





2.4.1.2

Mineralogy data is available for the The RVGU\_209 has FTIR, while the other two wells have XRD data. Nine samples show an average of 29% total clay, with mixed layer illite/smectite being the dominant species, with kaolinite and chlorite still prevalent. They also contain 32% quartz, 39% plagioclase and potassium feldspar, minimal pyrite, and less than 1% calcite & dolomite.

# 2.4.1.3

Mineralogy data is available for the from the week well. Nine samples show an average of 46% total clay, with mixed layer illite/smectite being the dominant species, with kaolinite and chlorite still prevalent. They also contain 23% quartz, 29% plagioclase and potassium feldspar, 2% pyrite, and 1% calcite & dolomite.

### 2.4.2 Porosity and Permeability

# 2.4.2.1

Wireline log data was acquired with measurements that include but are not limited to spontaneous potential, natural gamma ray, borehole caliper, compressional sonic, resistivity as well as neutron porosity and bulk density.

Formation porosity is determined one of two ways: from bulk density using 2.65 g/cc matrix density as calibrated from core grain density and core porosity data, or from compressional sonic using 55.5  $\mu$ sec/ft matrix slowness and the Raymer-Hunt equation.

Volume of clay is determined by spontaneous potential and is calibrated to core data.

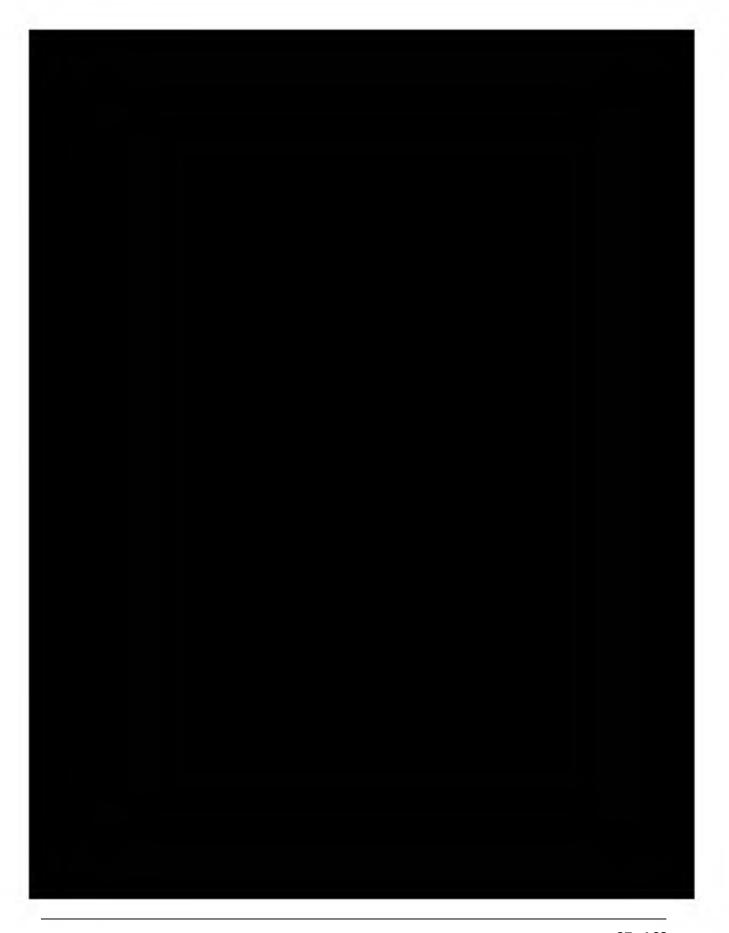
Log-derived permeability is determined by applying a core-based transform that utilizes capillary pressure porosity and permeability along with clay values from x-ray diffraction or Fourier transform infrared spectroscopy. Core data from two wells with 13 data points was used to develop a permeability transform. An example of the transform from core data is illustrated in **Figure 2.4-2** below.

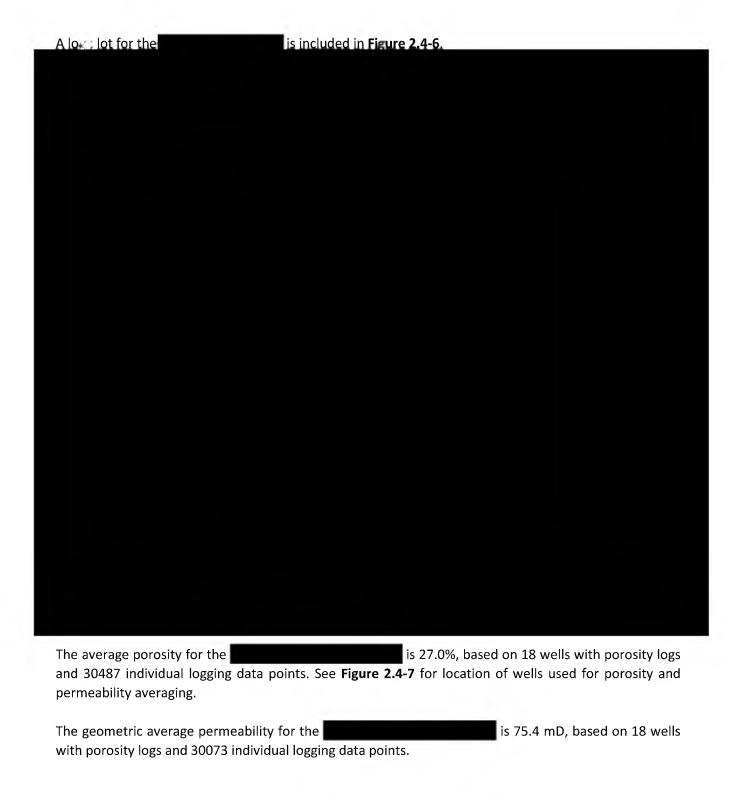


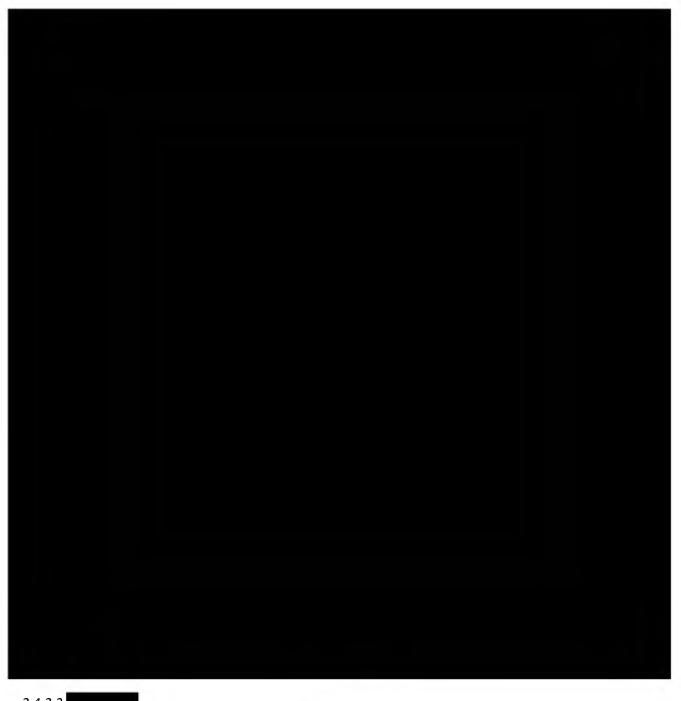
Comparison of the permeability transform to log generated permeability (Timur-Coates method) from a nuclear magnetic resonance (NMR) log in the Citizen\_Green\_1 well in King Island Gas Field is almost 1:1 and matches rotary sidewall core permeability over the (Figure 2.4-3). See Figure 2.4-1 for location of

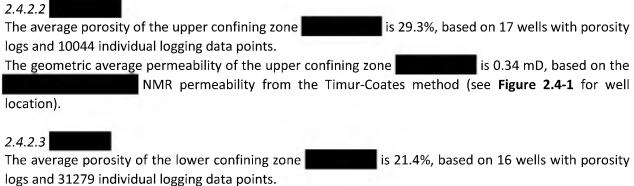


In the well are the porosity ranges from 1.5% - 34% with a mean of 26.5% (**Figure 2.4-4**). The permeability ranges from 0.003 mD - 697 mD with a log mean of 68 mD (**Figure 2.4-5**).









The geometric average permeability of the lower confining zone is 0.49 mD, based on 16 wells with porosity logs and 30853 individual logging data points.

### 2.4.3 Confining Zone Capillary Pressure

Capillary pressure is the difference across the interface of two immiscible fluids. Capillary entry pressure is the minimum pressure required for an injected phase to overcome capillary and interfacial forces and enter the pore space containing the wetting phase.

No capillary pressure data was available for the preoperational testing.

# 2.4.4 Depth and Thickness

Depths and thickness of the reservoir and confining zone (**Table 2.4-2**) are determined by structural and isopach maps (**Figure 2.4-8**) based on well data (wireline logs). Variability of the thickness and depth measurements is due to:

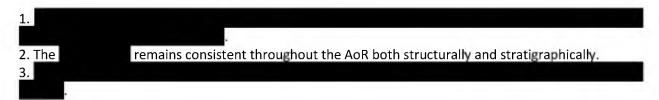
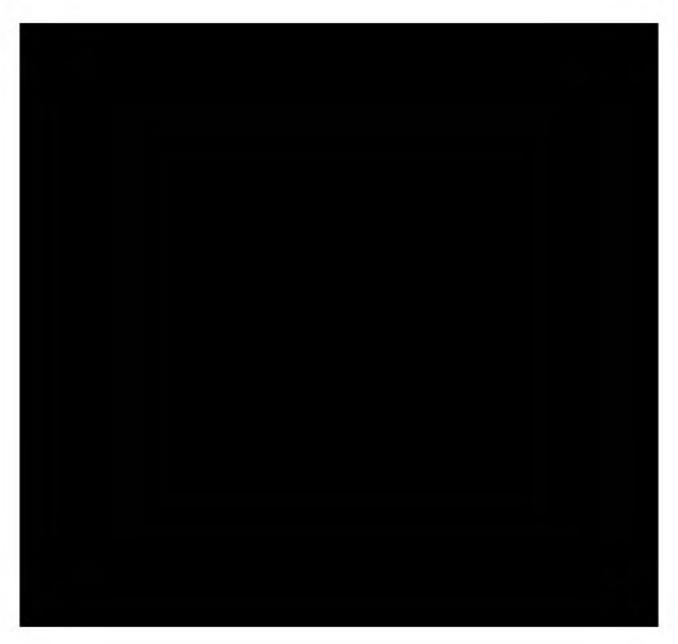


Table 2.4-2: gross thickness and depth within the AoR. Zone Property High Low Mean Upper Confining Zone Thickness (feet) 100 360 207 Depth (feet TVD) 4,954 6,164 5,582 Reservoir Thickness (feet) 316 1,336 1,024 Depth (feet TVD) 5,044 10,281 7,395



### 2.4.5 Structure Maps

Structure maps are provided in order to indicate a depth to reservoir adequate for supercritical-state injection.

## 2.4.6 Isopach Maps

Spontaneous potential (SP) logs from surrounding gas wells were used to identify sandstones. Negative millivolt deflections on these logs, relative to a baseline response in the enclosing shales, define the sandstones. These logs were baseline shifted to 0mV. Due to the log vintage variability, there is an effect on quality which creates a degree of subjectivity within the gross sand, however this will not have a material impact on the maps.

Variability in the thickness and depth of either the will not impact confinement. CTV will utilize thickness and depth shown when determining operating parameters and assessing project geomechanics.

#### 2.5 Geomechanical and Petrophysical Information [40 CFR 146.82(a)(3)(iv)]

## 2.5.1 Caprock Ductility

Ductility and the unconfined compressive strength (UCS) of shale are two properties used to describe geomechanical behavior. Ductility refers to how much a rock can be distorted before it fractures, while the UCS is a reference to the resistance of a rock to distortion or fracture. Ductility generally decreases as compressive strength increases.

Ductility and rock strength calculations were performed based on the methodology and equations from Ingram & Urai, 1999 and Ingram et. al., 1997. Brittleness is determined by comparing the log derived unconfined compressive strength (UCS) vs. an empirically derived UCS for a normally consolidated rock ( $UCS_{NC}$ ).

$$\log UCS = -6.36 + 2.45 \log(0.86V_p - 1172) \tag{1}$$

$$\sigma' = OB_{pres} - P_p \tag{2}$$

$$UCS_{NC} = 0.5\sigma' \tag{3}$$

$$BRI = \frac{UCS}{UCS_{NC}} \tag{4}$$

Units for the UCS equation are *UCS* in MPa and  $V_p$  (compressional velocity) in m/s.  $OB_{pres}$  is overburden pressure,  $P_p$  is pore pressure,  $P_p$  is effective overburden stress, and  $P_p$  is brittleness index.

If the value of BRI is less than 2, empirical observation shows that the risk of embrittlement is lessened, and the confining zone is sufficiently ductile to accommodate large amounts of strain without undergoing brittle failure. However, if BRI is greater than 2, the "risk of development of an open fracture network cutting the whole seal depends on more factors than local seal strength and therefore the BRI criterion is likely to be conservative, so that a seal classified as brittle may still retain hydrocarbons" (Ingram & Urai, 1999).

# 2.5.1.1

Within the AoR, six wells had compressional sonic and bulk density data over the ductility, comprising 3,769 individual logging data points, see pink squares in **Figure 2.4-1**. 15 wells had compressional sonic data over the document to calculate UCS, comprising 9413 individual logging data points, see black circles in **Figure 2.4-1**. The average ductility of the confining zone based on the mean value is 1.50. The average rock strength of the confining zone, as determined by the log derived UCS equation above, is 2,091 psi.

An example calculation for the well section is shown below (Figure 2.5-1). UCS\_CCS\_VP is the UCS based on the compressional velocity, UCS\_NC is the UCS for a normally consolidated rock, and BRI is the calculated brittleness using this method. Brittleness less than two (representing ductile rock) is shaded red.



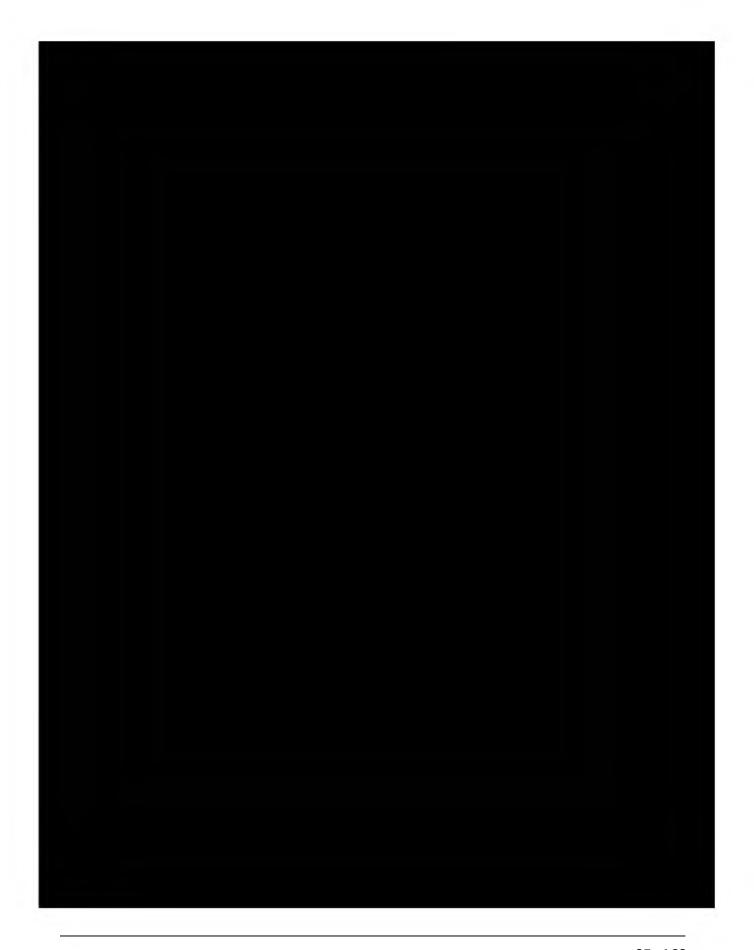
Within the above the above the has a brittleness value less than two. Additionally, the ductility, there are no fractures that will act as conduits for fluid migration from the

## 2.5.2 Stress Field

The stress of a rock can be expressed as three principal stresses. Formation fracturing will occur when the pore pressure exceeds the least of the stresses. in this circumstance, fractures will propagate in the direction perpendicular to the least principal stress (**Figure 2.5-2**).



Stress orientations in the Sacramento basin have been studied using both earthquake focal mechanisms and borehole breakouts (Snee and Zoback, 2020, Mount and Suppe, 1992). The azimuth of maximum principal horizontal stress ( $S_{Hmax}$ ) was estimated at the by Mount and Suppe, 1992. Data from the World Stress Map 2016 release (Heidbach et al., 2016) shows an average  $S_{Hmax}$  azimuth of several far field earthquakes with radically different  $S_{Hmax}$  orientations are removed (**Figure 2.5-3**), which is consistent with Mount and Suppe, 1992. The earthquakes in the area indicate a strike-slip/reverse faulting regime.



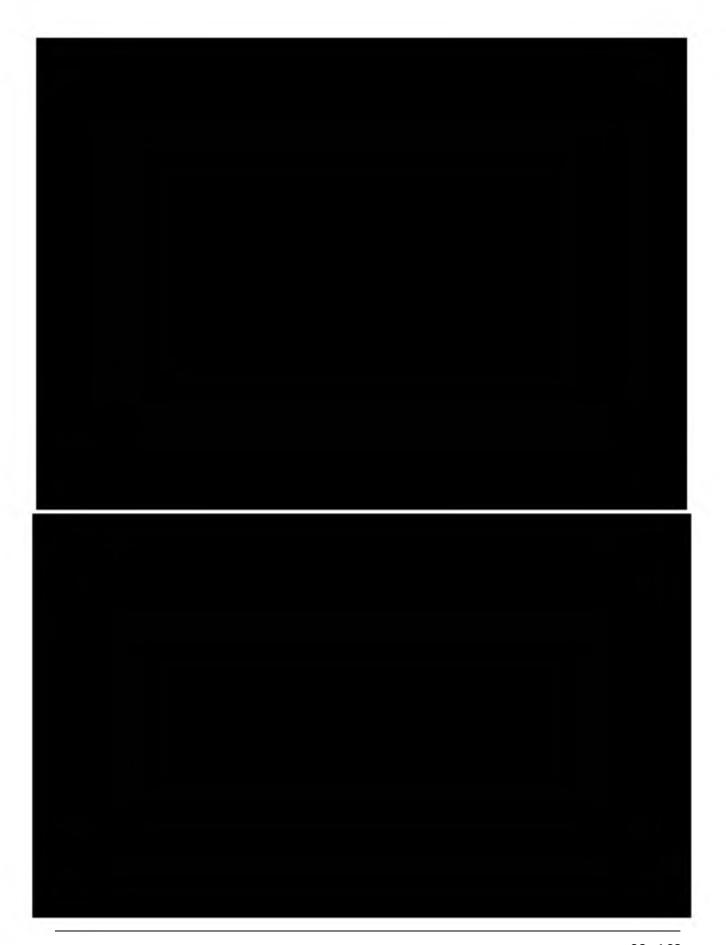
plan. However, several wells in the Two wells recorded minimum fracture gradients of 0.75-0.76 psi/ft based on FIT in the For the computational simulation modeling and well performance modeling, a frac	In the project AoR there is no site specific fracture pressure or fracture
psi/ft based on FIT in the For the computational simulation modeling and well performance modeling, a frac	gradient. A step rate test will be conducted as per the pre-operational testing
psi/ft based on FIT in the For the computational simulation modeling and well performance modeling, a frac	plan. However, several wells in the have formation integrity tests (FIT) for the
For the computational simulation modeling and well performance modeling, a frac	Two wells recorded minimum fracture gradients of 0.75-0.76
	psi/ft based on FIT in the , see <b>Figure 2.5</b> -
gradient of 0.76 psi/ft was assumed for now.	For the computational simulation modeling and well performance modeling, a frac
	gradient of 0.76 psi/ft was assumed for now.
In the project AoR there is no site specific fracture pressure or fracture gradient. A	In the project AoR there is no site specific fracture pressure or fracture gradient. A
step rate test will be conducted as per the pre-operational testing plan. In the interim, CTV is making	
8.23.28	

The overburden stress gradient in the reservoir and confining zone is 0.91 psi/ft. No data currently exists for the pore pressure of the confining zone. This will be determined as part of the preoperational testing plan.

# 2.6 Seismic History [40 CFR 146.82(a)(3)(v)]



The United States Geologic Survey (USGS) provides an earthquake catalog tool (https://earthquake.usgs.gov/earthquakes/search/) which can be used to search for recent seismicity that could be associated with faults in the area for movement. A search was made for earthquakes in the greater vicinity of the project area from 1850 to modern day with events of a magnitude greater than three. **Figure 2.6-2** shows the results of this search. **Table 2.6-1** summarizes some of the data taken from them.





Event 8 appears to be isolated from the fault zones at a depth of 6km. Reviewing the 3D seismic data in that area there may be a structural feature at the level of seismic basement, but it is not well imaged. The event does not continue into the shallower sediments that are thousands of feet deeper than the proposed injection zone. Similar can be said for event 13, another deep (6km) event that is outside of the AoR.

For the event numbers 2 and 7 are clearly related to the fault trace. Event 7 was a significant distance from the AoR and event 2 was significantly deeper (14.55km) than the proposed injection zone. Finally, events 3, 12, and 14 are in the closest proximity to the event 14 appears to align with the event 14 amapped fault by the CGS that may be a splay of the event 12 is interpreted to be at a significant depth (14.95km) away from the injection zone and far beneath the sedimentary section of the basin. Event 3 is likely the most concerning, this earthquake happened in 2002, at the approximate seismic basement level which is interpreted to be around 16,000 ft (4.88km). The average depth of prior seismic events in the region based on these data (Table 2.6-1) is approximately 9.3km, far deeper than the proposed injection zone and sedimentary section.

Our modeling shows the to be under-pressured across the AoR, which will be confirmed in pre-operational testing.

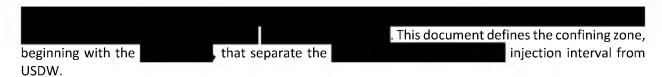
As stated previously, given that other formations around these faults

have held back hydrocarbons at pressures above hydrostatic, we believe this to be a safe standard for fault stability.

Lund-Snee and Zoback (2020) published updated maps for crustal stress estimates across North America. Figure 2.6-4 shows a modified image from that work highlighting the CTV III area. This work agrees with previous estimates of maximum horizontal stress in the region of approximately N40°E in a strike-slip to reverse stress regime (Mount and Suppe, 1992) and is consistent with World Stress map data for the area (Heidbach et al, 2016). Attachment C of this application discusses the seismicity monitoring plan for this injection site.



### 2.6.2 Seismic Hazard Mitigation



The following is a summary of CTVs seismic hazard mitigation for CTV III:

The project has a geologic system capable of receiving and containing the volumes of CO<sub>2</sub> proposed to be injected



Will be operated and monitored in a manner that will limit risk of endangerment to USDWs, including risks associated with induced seismic events

- Injection pressure will be lower than the fracture gradient of the sequestration reservoir with a safety factor (90% of the fracture gradient)
- Injection and monitoring well pressure monitoring will ensure that pressures are beneath the
  fracture pressure of the sequestration reservoir and confining zone. Injection pressure will be
  lower than the fracture gradients of the sequestration reservoir and confining zone with a
  safety factor (90% of the fracture gradients)
- A seismic monitoring program will be designed to detect events lower than seismic events that can be felt. This will ensure that operations can be modified with early warning events, before a felt seismic event

Will be operated and monitored in a way that in the unlikely event of an induced event, risks will be quickly addressed and mitigated

- Via monitoring and surveillance practices (pressure and seismic monitoring program) CTV
  personnel will be notified of events that are considered an early warning sign. Early warning
  signs will be addressed to ensure that more significant events do not occur
- CTV will establish a central control center to ensure that personnel have access to the continuous data being acquired during operations

#### Minimizing potential for induced seismicity and separating any events from natural to induced

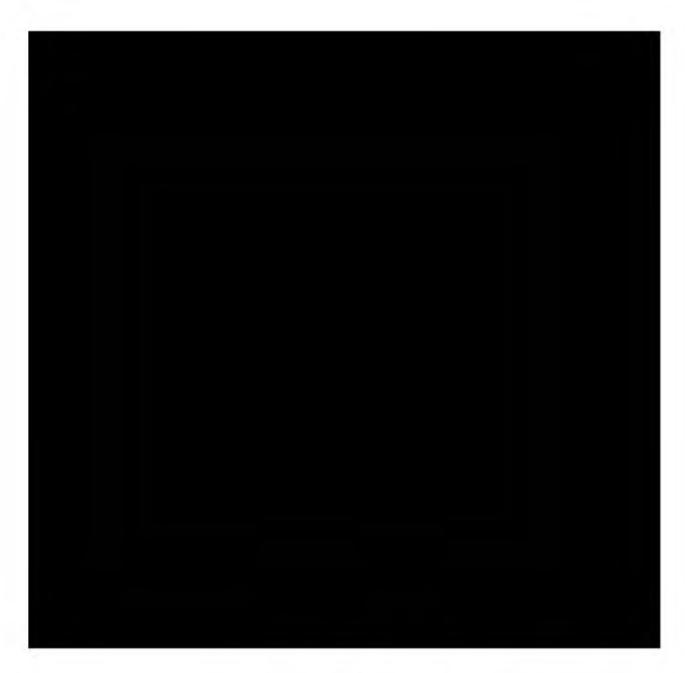
- Pressure will be monitored in each injector and sequestration monitoring well to ensure that
  pressure does not exceed the fracture pressure of the reservoir or confining zone
- Seismic monitoring program will be installed pre-injection for a period to monitor for any baseline seismicity that is not being resolved by current monitoring programs
- Average depth of prior seismic hazard in the region based on reviewed historical seismicity has been approximately 9.3km. Significantly deeper than the proposed injection zone

# 2.7 Hydrologic and Hydrogeologic Information [40 CFR 146.82(a)(3)(vi), 146.82(a)(5)]

The California Department of Water Resources has defined 515 groundwater basins and subbasins with the state.

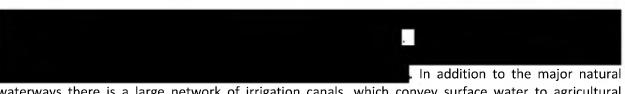
Figure 2.7-1 shows the AoR,

, and the surrounding areas. The Subbasin encompasses an area of about in San Joaquin (DWR 2006).



# 2.7.1 Hydrologic Information

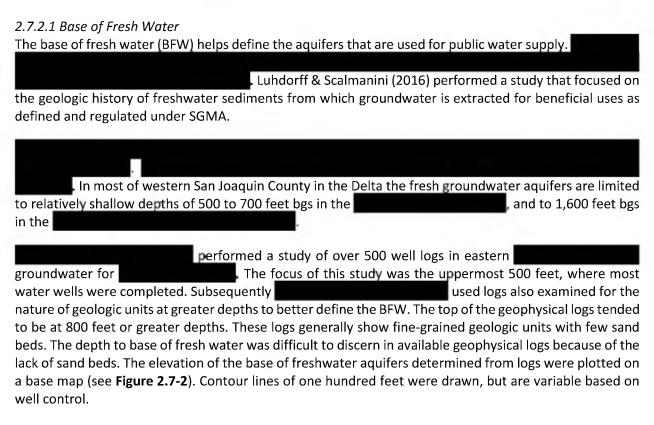
Major surface water bodies within the consist of the Figure 2.7-1 shows the location of these surface water bodies. The entire eastern boundary of the Subbasin and it feeds water into the located just west of the Subbasin.



waterways there is a large network of irrigation canals, which convey surface water to agricultural properties.

#### 2.7.2 Base of Fresh Water and Base of USDWs

The owner or operator of a proposed Class VI injection well must define the general vertical and lateral limits of all USDWs and their positions relative to the injection zone and confining zones. The intent of this information is to demonstrate the relationship between the proposed injection formation and any USDWs, and it will support an understanding of the water resources near the proposed injection wells. A USDW is defined as an aquifer or its portion which supplies any public water system; or which contains a sufficient quantity of ground water to supply a public water system; and currently supplies drinking water for human consumption; or contains fewer than 10,000 mg/l total dissolved solids; and which is not an exempted aquifer.





# 2.7.2.2 Calculation of Base of Fresh Water and USDW

CRC has used geophysical logs to investigate the USDWs and the base of the USDWs. The calculation of salinity from logs used by CRC is a four-step process:

(1) converting measured density or sonic to formation porosity

The equation to convert measured density to porosity is:

$$POR = \frac{(Rhom - RHOB)}{(Rhom - Rhof)} \tag{5}$$

Parameter definitions for the equation are:

POR is formation porosity

Rhom is formation matrix density grams per cubic centimeters (g/cc); 2.65 g/cc is used for sandstones

RHOB is calibrated bulk density taken from well log measurements (g/cc)  $\,$ 

Rhof is fluid density (g/cc); 1.00 g/cc is used for water-filled porosity

The equation to convert measured sonic slowness to porosity is:

$$POR = -1\left(\frac{\Delta tma}{2\Delta tf} - 1\right) - \sqrt{\left(\frac{\Delta tma}{2\Delta tf} - 1\right)^2 + \frac{\Delta tma}{\Delta t \log} - 1}$$
 (6)

Parameter definitions for the equation are:

POR is formation porosity

 $\Delta$ tma is formation matrix slowness ( $\mu$ s/ft); 55.5  $\mu$ s/ft is used for sandstones  $\Delta$ tf is fluid slowness ( $\mu$ s/ft); 189  $\mu$ s/ft is used for water-filled porosity  $\Delta$ tlog is formation compressional slowness from well log measurements ( $\mu$ s/ft)

(2) calculation of apparent water resistivity using the Archie equation,

The Archie equation calculates apparent water resistivity. The equation is:

$$Rwah = \frac{POR^m R_t}{a} \tag{7}$$

Parameter definitions for the equation are:

Rwah is apparent water resistivity (ohmm)

POR is formation porosity

m is the cementation factor; 2 is the standard value

Rt is deep reading resistivity taken from well log measurements (ohmm)

a is the archie constant; 1 is the standard value

(3) correcting apparent water resistivity to a standard temperature

Apparent water resistivity is corrected from formation temperature to a surface temperature standard of 75 degrees Fahrenheit:

$$Rwahc = Rwah \frac{TEMP + 6.77}{75 + 6.77} \tag{8}$$

Parameter definitions for the equation are:

Rwahc is apparent water resistivity (ohmm), corrected to surface temperature TEMP is down hole temperature based on temperature gradient (DegF)

(4) converting temperature corrected apparent water resistivity to salinity.

The following formula was used (Davis 1988):

$$SAL_a EPA = \frac{5500}{Rwahc} \tag{9}$$

Parameter definitions for the equation are:

SAL\_a\_EPA is salinity from corrected Rwahc (ppm)

The base of fresh water and the USDW are shown on the geologic Cross Section A-A' (**Figure 2.2-4**) The base of fresh water and based of the lowermost USDW is at a measure depth of approximately 1100 ft and 2500 ft respectively.



The Alluvium (Q) includes sediments deposited in the channels of active streams as well as overbank deposits and terraces of those streams. They consist of unconsolidated silt, sand, and gravel. Sand and gravel zones in the younger alluvium are highly permeable and yield significant quantities of water to wells. The thickness of the younger alluvium in the line is less than 100 feet (DWR 2006).

#### 2.7.3.2 Flood Basin and Intertidal Deposits

The Flood Basin Deposits and Intertidal Deposits (Qi) are in the Delta portions of the Subbasin. These sediments consist of peaty mud, clay, silt, sand and organic materials. Stream-channel deposits of coarse sand and gravel are also included in this unit. The flood basin deposits have low permeability and generally yield low quantities of water to wells due to their fine-grained nature. Flood basin deposits generally contain poor quality groundwater with occasional zones of fresh water. The maximum thickness of the unit is about 1,400 feet (DWR 2006).

## 2.7.3.3 Alluvial Fan Deposits

Along the southern margin of the Subbasin, in the Non-Delta uplands areas of the Subbasin are fan deposits (Qf) from the Coast Ranges. These deposits consist of loosely to moderately compacted sand, silt, and gravel deposited in alluvial fans during the Pliocene and Pleistocene ages. The fan deposits likely interfinger with the Flood Basin Deposits. The thickness of these fans is about 150 feet (DWR 2006).

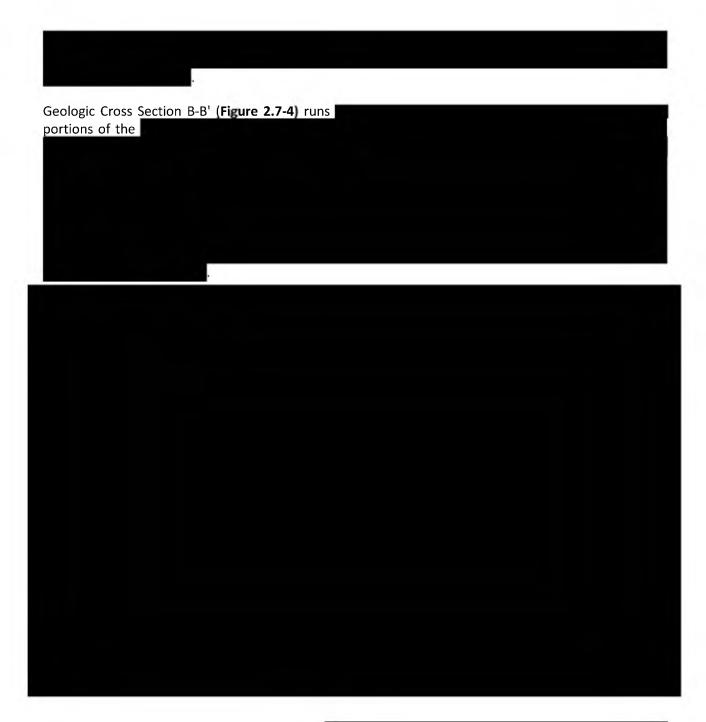




## 2.7.3.6 Undifferentiated Non-marine Sediments

The upper Paleogene and Neogene sequence begin with the Valley Springs Formation which represents fluvial deposits that blanket the entire southern Sacramento Basin. The unconformity at the base of the Valley Springs marks a widespread Oligocene regression and separates the more deformed Mesozoic and lower Paleogene strata below from the less deformed uppermost Paleogene and Neogene strata above. The undifferentiated non-marine sediments contain approximately 3,000 - 10,000 milligrams per liter (mg/l) TDS water and is the lowermost USDW in the AoR (**Figure 2.2-3**).

2.7.4 Geolo-ic Cross Sections Illustratin. Formations with USDWs
The soil profiles show the subsurface relationships and location of the formations and
coarse-grained sediments that comprise the principal aquifers.



Geologic Cross Section C-C' (Figure 2.7-5) runs

This geologic section illustrates the types of sediments, the estimated base of freshwater, the possible location of the Corcoran Clay (or its equivalent). Where the clay location is uncertain, no wells were present that penetrated deep enough to confirm its presence or absence. The base of fresh water varies throughout the Subbasin and is shown on the sections. It is as shallow as -400 feet mean sea level (msl) to as much as -2,000 feet msl (GEI 2021).



# 2.7.5 Princi, al Aquifers

# 2.7.5.1 Upper Aquifer

The Upper Aquifer is used by domestic, community water systems, and for agriculture. The Upper aquifer also supports native vegetation where groundwater levels are less than 30 feet bgs (GEI 2021). The Upper Aquifer is an unconfined to semi-confined aquifer. It is present above the Corcoran Clay and where the clay is absent. The Upper aquifer exists in the Alluvial Fan Deposits, Intertidal Deposits, Modesto Formation, Flood Basin Deposits, the upper portions of the Tulare Formation.

There are multiple coarse-grained sediment layers that make up the unconfined aquifer, however the water levels are generally similar. Generally, the aquifer confinement tends increase with depth becoming semi-confined conditions. There is also typically a downward gradient in the aquifers (Hotchkiss and Balding 1971) in the non-Delta areas; the gradient ranges from a few feet bgs to as much as 70 feet bgs. The groundwater levels in the Upper Aquifer are usually 10 to 30 feet higher than in the Lower Aquifer. The groundwater levels In the Delta are typically at sea level and artesian flowing wells are common in the center of the islands (Hydrofocus 2015).

The hydraulic characteristics of the unconfined aquifer are highly variable. The USGS estimated horizontal hydraulic conductivity values for organic sediments ranging from 0.0098 ft/d to 133.86 ft/d (Hydrofocus 2015). Wells in the unconfined aquifer produce 6 to 5,300 gpm. The transmissivity of the unconfined aquifers, ranges between 600 to greater than 2,300 gallons per day per foot (gpd/ft). The storativity is about 0.05 (GEI 2021).

Water quality in the Upper Aquifer is mostly transitional, with no single predominate anion. Most water are characterized as sulfate bicarbonate and chloride bicarbonate type (Hotchkiss and Balding 1971). The TDS of these transitional water ranges between 400 to 4,200 mg/L. Nitrate is generally high in the Upper aquifer in the non-Delta portions of the Subbasin. Nitrate is generally low in the Delta portions of the Subbasin (GEI 2021).

#### 2.7.5.2 Lower Aquifer

The Lower Aquifer is typically used by community water systems and agriculture. The Lower Aquifer is mainly comprised of the lower portions of the Tulare Formation below the Corcoran Clay and extends to the base of fresh water. The clay is present in the southern third of the Subbasin; the clay's extent to the west and north is uncertain and has been estimated to have a vertical permeability ranging from 0.01 to 0.007 feet per day (Burow et al. 2004).

The groundwater levels are generally deeper than water levels in the Upper Aquifer (Hotchkiss and Balding 1971). Groundwater levels in the confined aquifer are about -25 to -75 feet msl. The groundwater levels are normally 60 to 200 feet above the top of the Corcoran Clay.

Wells in the Lower Aquifer produce about 700 to 2,500 gpm. The transmissivity typically ranges from 12,000 to 37,000 gpd/ft, but can be 120,000 gpd/ft. The storage coefficient or storativity has been measured to be 0.0001 (Padre 2004).

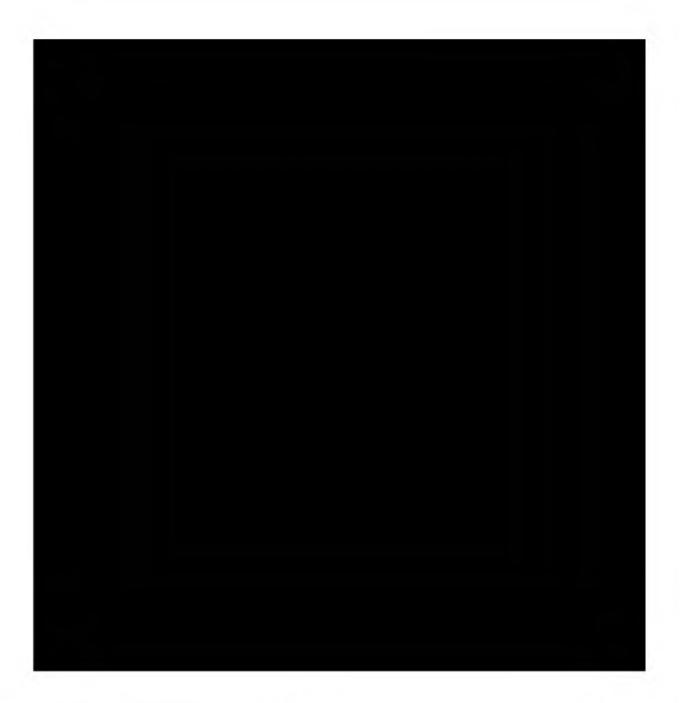
Water quality in the Lower Aquifer in the western portions are chloride type water but mostly transitional type of sulfate chloride near the valley margins and sulfate bicarbonate and bicarbonate sulfate near the San Joaquin River (Hotchkiss and Balding 1971). In general, the TDS ranges between 400 and 1,600 mg/L. Nitrate is typically low in the Lower Aquifer. Wells completed below the Corcoran Clay sometimes have elevated levels sulfate and total dissolved solids above the drinking water MCLs. Only at one deep location, are chloride levels elevated (GEI 2021).

### 2.7.6 Potentiometric Maps

The used groundwater level measurements in over 226 wells, which have been reported to DWR's CASGEM or Water Data Library systems. To evaluate groundwater levels, the GSP only used wells with known total depths and construction details so that the wells were assigned to a principal aquifer. To supplement data from these wells, additional monitoring wells were located that were being used for other regulatory programs.

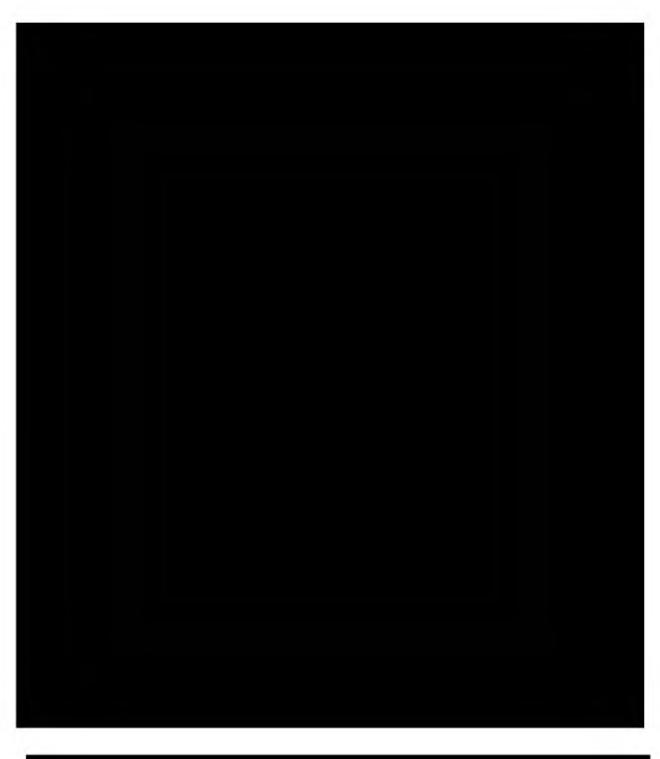
2.7.6.1 Upper Aquifer

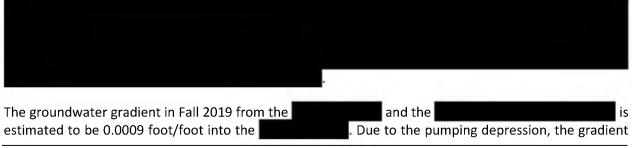




# 2.7.6.2 Lower Aquifer

The Corcoran Clay extends throughout the Groundwater contours for the Lower Aquifer were developed using data from the CASGEM monitoring wells that are constructed below the Corcoran Clay and supplemented by data from municipal wells (Figure 2.7-8). Groundwater monitoring well data were used from the





increases around the The gradient near the western edge of the subbasin cannot be determined to the lack of monitoring wells constructed below the Corcoran Clay (GEI 2021).

#### 2.7.7 Water Supply Wells

The California State Water Resources Control Board Groundwater Ambient Monitoring Assessment Program (GAMA), and the Department of Water Resources (DWR) public databases were searched to identify any water supply wells within a one-mile radius of the AOR. A total of 155 water supply wells were identified within one mile of the AoR. A map of well locations and table of information are found in **Figure 2.7-9** Water Well Location Map and the attached **Table 2.7-1** Water Well Information, respectively.



Groundwater in the Subbasin is used for municipal, industrial, irrigation, domestic, stock watering, frost protection, and other purposes. The number of water wells is based on well logs filed and contained within public records may not reflect the actual number of active wells because many of the wells contained in files may have been destroyed and others may not have been recorded.



The known water well depths and other information are included in the attached **Table 2.7-1.** Some well depths are unknown, but all water supply wells completion intervals are expected to be much shallower than the injection zone.

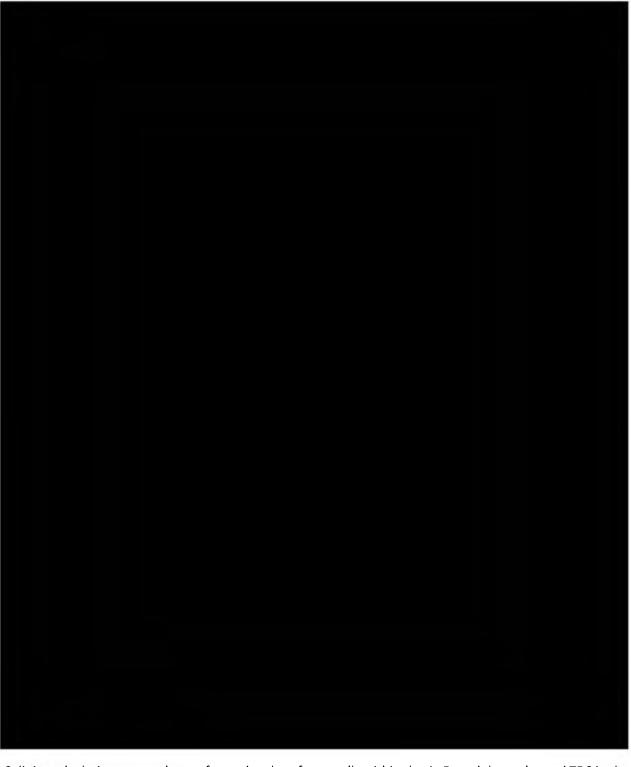
## 2.8 Geochemistry [40 CFR 146.82(a)(6)]

## 2.8.1 Formation Geochemistry



## 2.8.2 Fluid Geochemistry

The well was sampled in 1980 (see **Figure 2.5-4** for well location). The measurement of total dissolved solids (TDS) for the sample is 13,889.4 mg/L. The complete water chemistry is shown in **Figure 2.8-1**.



Salinity calculations were also performed on logs from wells within the AoR, and these showed TDS in the being approximately 14,000 - 16,000 ppm. A conservative TDS of 15,500 ppm was used for the computational model.

# 2.8.3 Fluid-Rock Reactions



# 2.9 Other Information (Including Surface Air and/or Soil Gas Data, if Applicable)

No additional information to add.

# 2.10 Site Suitability [40 CFR 146.83]

Sufficient data from both wells and seismic demonstrate the integrity through lateral continuity of the reservoir as well as the confining zone.

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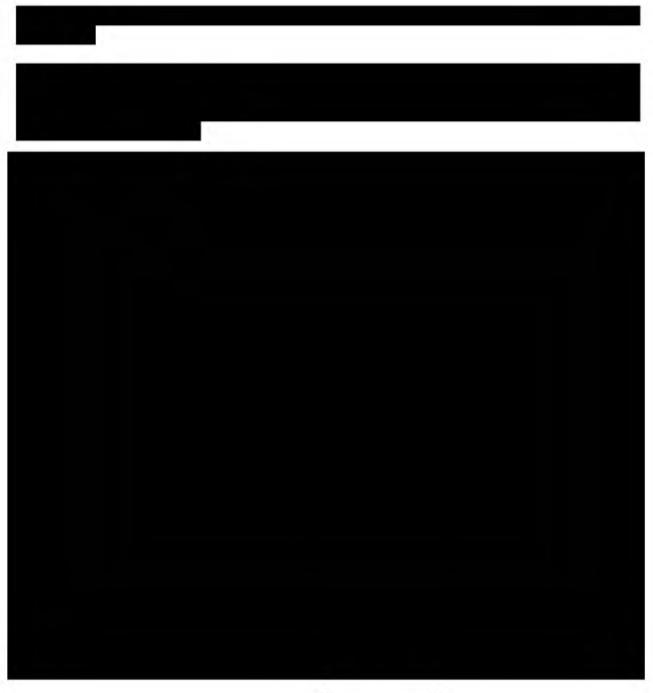
I have a summary of the reservoir as well as the confining zone.

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CTV's estimates storage for the project area is up to This was arrived through computational modeling.

### 3.0 AoR and Corrective Action

CTV's AoR and Corrective Action plan pursuant to 40 CFR 146.82(a)(4), 40 CFR 146.82(a)(13) and 146.84(b), and 40 CFR 146.84(c) describes the process, software, and results to establish the AoR, and the wells that require corrective action.

AoR and Corrective Action GSDT Submissions

GSDT Module: AoR and Corrective Action

**Tab(s):** All applicable tabs

Please use the checkbox(es) to verify the following information was submitted to the GSDT:

- ☐ Tabulation of all wells within AoR that penetrate confining zone [40 CFR 146.82(a)(4)]
- $\boxtimes$  AoR and Corrective Action Plan [40 CFR 146.82(a)(13) and 146.84(b)]
- ☑ Computational modeling details [40 CFR 146.84(c)]

#### 4.0 Financial Responsibility

CTV's Financial Responsibility demonstration pursuant to 140 CFR 146.82(a)(14) and 40 CFR 146.85 is met with a line of credit for Injection Well Plugging and Post-Injection Site Care and Site Closure and insurance to cover Emergency and Remedial Responses.

Financial Responsibility GSDT Submissions

**GSDT Module:** Financial Responsibility Demonstration

Tab(s): Cost Estimate tab and all applicable financial instrument tabs

Please use the checkbox(es) to verify the following information was submitted to the GSDT:

☐ Demonstration of financial responsibility [40 CFR 146.82(a)(14) and 146.85]

### 5.0 Injection and Monitoring Well Construction

CTV plans to drill six new injectors for the CTV III storage project. New injection wells C1, C2, E1, E2, W1, and W2 are planned and designed specifically for CO<sub>2</sub> sequestration purposes. These wells will target selective intervals within the injection zone to optimize plume development and injection conformance. Additionally, three new monitoring wells are required to support the storage project. M1 and M2 will be injection zone monitoring wells, and D1 will be an above-zone monitoring well. Two USDW monitoring wells, US1 and US2, will also be constructed prior to injection.

Injection and monitoring well construction is addressed in Attachment G: Well Construction and Testing of the application, which includes the well construction approach for all proposed injection and monitoring wells. Appendix C-1: Injection and Monitoring Well Schematics provides casing diagrams, well construction tables, and completion details.

#### 5.1 Proposed Stimulation Program [40 CFR 146.82(a)(9)]

There are no proposed stimulation programs currently.

### 5.2 Construction Procedures [40 CFR 146.82(a)(12)]

Injection and monitoring wells will be drilled during pre-operational testing, and no major drilling and completion issues are anticipated. The well will be constructed to prevent migration of fluids out of the

, protect the shallow formations, and allow for monitoring, as described by

the following:

- Well designs will be sufficient to withstand all anticipated load cases including safety factors
- Multiple cemented casing strings will protect shallow USDW-bearing zones from contacting injection fluid
- All casing strings will be cemented in place with volume sufficient to place cement to surface using industry-proven recommended practices for slurry design and placement
- Cement bond logging (CBL) will be used to verify presence of cement in the production casing annulus through and above the confining layer
- Mechanical integrity testing (MIT) will be performed on the tubing and the tubing/casing annulus. This is described in further detail in Attachment G: Construction Details.
- Upper completion design enables monitoring devices to be installed downhole, cased hole logs to be acquired and MIT to be conducted.
- All wellhead equipment and downhole tubulars will be designed to accommodate the dimensions necessary for deployment of monitoring equipment such as wireline-conveyed logging tools and sampling devices.
- Realtime surface monitoring equipment with remote connectivity to a centralized facility and alarms provides continual awareness to potential anomalous injection conditions
- Annular fluid (packer fluid) density and additives to mitigate corrosion provide additional protection against mechanical or chemical failure of production casing and upper completion equipment

Well materials utilized will be compatible with the CO<sub>2</sub> injectate and will limit corrosion.

- Wellhead stainless steel or other corrosion resistant alloy
- Casing 13Cr L-80 or other corrosion resistant alloy in specified sections of production string (ie. flow-wetted casing)
- Cement Portland cement has been used extensively in enhanced oil recovery (EOR) injectors.
   Data acquired from existing wells supports that the materials are compatible with CO2 where good cement bond between formation and casing exists.
- Tubing 13Cr L-80 or other corrosion resistant alloy
- Packer corrosion resistant alloy and hardened elastomer

Well materials follow the following standards:

- API Spec 6/CT ISO 11960 Specifications for Casing and Tubing
- API Spec 10A/ISO 10426-1 Specifications for Cements and Materials for Cementing
- API Spec 11D1/ISO 14310 Downhole Equipment Packers and Bridge Plugs

#### 5.2.1 Casing and Cementing

Well-specific casing diagrams including casing specifications are presented in Appendix C-1: Injection and Monitoring Well Schematics to meet the requirements of 40 CFR 146.86(b)(1)(iv). These specifications are sufficient to allow for the safe operation at bottomhole injection conditions that will not exceed the maximum allowable operating pressure (MAOP) of 0.684 psi/ft specified in the Appendix: Operating Procedures.

These conditions are not extreme, and standard cementing and casing best practices are sufficient to ensure successful placement and isolation. Industry

standard practices and procedures for designing and placing primary cement in the casing annuli will be utilized to ensure mechanical integrity of cement and casing. Staged cementing is not an anticipated requirement.

Operational parameters acquired throughout the cementing operation will be used to compare modeled versus actual pressure and rate. The presence of circulated cement at surface will also be a primary indicator of effective cement placement. Cement evaluation logging will be conducted to confirm cement placement and isolation.

#### 5.2.2 Tubing and Packer

The information in the tables provided in Appendix C-1: Injection and Monitoring Well Schematics is representative of completion equipment that will be used and meets the requirements at 40 CFR 146.86(c). Tubing and packer selection and specifications will be determined after well construction is completed during pre-operational testing.

### 6.0 Pre-Operational Logging and Testing

CTV has attached a Pre-Operational logging and testing plan pursuant to 40 CFR 146.82(a)(8) and 40 CFR 146.87.

Pre-Operational Logging and Testing GSDT Submissions

GSDT Module: Pre-Operational Testing

Tab(s): Welcome tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:

☑ Proposed pre-operational testing program [40 CFR 146.82(a)(8) and 146.87]

#### 7.0 Well Operation

CTV has provided detailed operating procedures for each injection well. These procedures are provided for all injectors in the Appendix – Operational Procedures document. The operational procedure for planned injector C1 is included below.

#### 7.1 Operational Procedures [40 CFR 146.82(a)(10)]

For a target rate of bottom hole and surface pressures have been estimated for injector C1 over the life of the project. These pressures were estimated using results from the Plume simulation as an input into the multiphase well nodal analysis software – PROSPER by Petroleum Experts Ltd. PROSPER has been used extensively in  $CO_2$  EOR to model  $CO_2$  injection wells. The pressures have been currently calculated assuming a 100%  $CO_2$  stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

At the start of injection, a surface and bottom hole injection pressure of 1,240 psi and 2,934 psi respectively, are required to inject. As the pressure in the reservoir builds up, higher surface and bottom hole pressures will be required. At the end of injection, the estimated surface and bottom hole pressures

required are 1,300 psi and 3,050 psi respectively, which is the maximum pressure CTV expects to operate the well under target rate conditions.

The expected fracture pressure gradient for the injection zone is estimated to be 0.76psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable BHP is 4,224 psi (calculated at the top perforation). The injection well will be controlled using automation to never exceed this maximum BHP.

The expected pressures for injector C1 over the life of the project are summarized in Table 7.1.1 and in the Operational Procedures Appendix.

Table 7.1.1. Proposed operational procedures for Injector C1.

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Allowable Pressure	Using 0.76psi/ft frac gradient with 10% safety factor	
Surface	2243	psig
Downhole	4224	psig
Injection Pressure @ Target rate	Expected range over project	
Surface - Start / End	1240 / 1300	psig
Downhole - Start / End	2934 / 3050	psig
Target Injection Rate		mmscfpd
		tons/day
Annulus Pressure	Expected range over project	
Surface - Start / End	100 / 315	psig
Downhole - Start / End	2725 / 1940	psig
Annulus / Injection Tubing Pressure Differential	>100	psig

#### 7.1.1 Annulus Pressure

Annular pressure between the tubing and production casing above the packer will be maintained to achieve the requirements of 40 CFR 146.88 (c).

The minimum applied annular surface pressure will be maintained at or greater than 100 psi during injection. This ensures a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to Attachment C: Testing and Monitoring Plan.

CTV will maintain downhole annular pressure at the packer greater than 100 psi above injection pressure for all bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure, as needed.

CTV intends to use 4% KCl completion fluid with corrosion inhibition and biocide as packer fluid. 4% KCl is compatible with all well components and is not corrosive. The specific gravity of the packer fluid is estimated to be 1.024.

The range of annular pressures described in Table 7.1.1 are suitable to the well design and will not impact the well integrity or induce formation fracture.

### 7.1.2 Maximum Injection Rate

Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the maximum injection rate.

At this time, for injection well C1, CTV expects a target injection rate of which the maximum expected bottom hole injection pressure is 3,050 psi. A threshold of 10% over these values will be used to configure automation and alarms, which equates to and 3,355 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue. Resolution will depend on the type of alarm and systems installed to regulate the injection rate. Typically, this will require a reduction in the injection rate without the need for a shutdown. But the situation will be reviewed to understand what systems failed or did not perform properly and thus created an excessive injection rate.

#### 7.1.3 Shutdown Procedures

Under routine shutdowns (e.g., for well workovers), CTV will reduce CO<sub>2</sub> injection at a rate of

#### 7.1.4 Automated Shutdown System

Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real time. Data will be collected in an automated system and monitored by a control system with established operating thresholds. After a threshold is seen or exceeded, the software will issue visual, audible, and digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate equipment until it is understood why the thresholds were achieved and what corrective measures must be implemented.

CTV has not established the monitoring system at this time. Upon establishing the system and thresholds CTV will communicate with the EPA.

#### 7.2 Proposed Carbon Dioxide Stream [40 CFR 146.82(a)(7)(iii) and (iv)]

There are currently multiple sources of anthropogenic CO₂ being considered for the project. These include capture from existing and potential future industrial sources in the Sacramento Valley area, as well as Direct Air Capture (DAC). The carbon dioxide stream will consist of a minimum of 95% CO₂ by volume. Other key constituents that will be controlled for corrosion mitigation include water content (<25 lb/mmscf) and oxygen level (<50 ppm)

Corrosiveness of the  $CO_2$  stream is very low as long as the entrained water is kept in solution with the  $CO_2$ . This is ensured by the < 25 lb/mmscf injectate specification referred to above. Injectate water solubility will vary with depth and time as temperature and pressures change. The water specification is conservative to ensure water solubility across super-critical operating ranges. CRA tubing will be used in the injection wells to mitigate this potential corrosion impact should free-phase water be present. CTV may optimize the maximum water content specification prior to injection based on technical analysis.

#### 8.0 Testing and Monitoring

CTV's Testing and Monitoring plan pursuant to 40 CFR 146.82 (a) (15) and 40 CFR 146.90 describes the strategies for testing and monitoring to ensure protection of the USDW, injection well mechanical integrity, and plume monitoring.

**Testing and Monitoring GSDT Submissions** 

**GSDT Module:** Project Plan Submissions **Tab(s):** Testing and Monitoring tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:

□ Testing and Monitoring Plan [40 CFR 146.82(a)(15) and 146.90]

# 9.0 Injection Well Plugging

CTV's Injection Well Plugging Plan pursuant to 40 CFR 146.92 describes the process, materials and methodology for injection well plugging.

Injection Well Plugging GSDT Submissions

**GSDT Module:** Project Plan Submissions **Tab(s):** Injection Well Plugging tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:

☑ Injection Well Plugging Plan [40 CFR 146.82(a)(16) and 146.92(b)]

### 10.0 Post-Injection Site Care (PISC) and Site Closure

CTV has developed a Post-Injection Site Care and Site Closure plan pursuant to 40 CFR 146.93 (a) to define post-injection testing and monitoring.

At this time CTV is not proposing an alternative PISC timeframe.

PISC and Site Closure GSDT Submissions

**GSDT Module:** Project Plan Submissions

Tab(s): PISC and Site Closure tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:

☑ PISC and Site Closure Plan [40 CFR 146.82(a)(17) and 146.93(a)]

PISC and Site Closure GSDT Submissions

GSDT Module: Alternative PISC Timeframe Demonstration

Tab(s): All tabs (only if an alternative PISC timeframe is requested)

Please use the checkbox(es) to verify the following information was submitted to the GSDT:

☑ Alternative PISC timeframe demonstration [40 CFR 146.82(a)(18) and 146.93(c)]

### 11.0 Emergency and Remedial Response

CTV's Emergency and Remedial Response plan pursuant to 40 CFR 164.94 describes the process and response to emergencies to ensure USDW protection.

**Emergency and Remedial Response GSDT Submissions** 

**GSDT Module:** Project Plan Submissions

Tab(s): Emergency and Remedial Response tab

Please use the checkbox(es) to verify the following information was submitted to the GSDT:

☑ Emergency and Remedial Response Plan [40 CFR 146.82(a)(19) and 146.94(a)]

## 12.0 Injection Depth Waiver and Aquifer Exemption Expansion

No depth waiver or Aquifer Exemption expansion is being requested as part of this application

Injection Depth Waiver and Aquifer Exemption Expansion GSDT Submissions
<b>GSDT Module:</b> Injection Depth Waivers and Aquifer Exemption Expansions <b>Tab(s):</b> All applicable tabs
Please use the checkbox(es) to verify the following information was submitted to the GSDT:  Injection Depth Waiver supplemental report [40 CFR 146.82(d) and 146.95(a)]  Aquifer exemption expansion request and data [40 CFR 146.4(d) and 144.7(d)]

#### 13.0 Reference

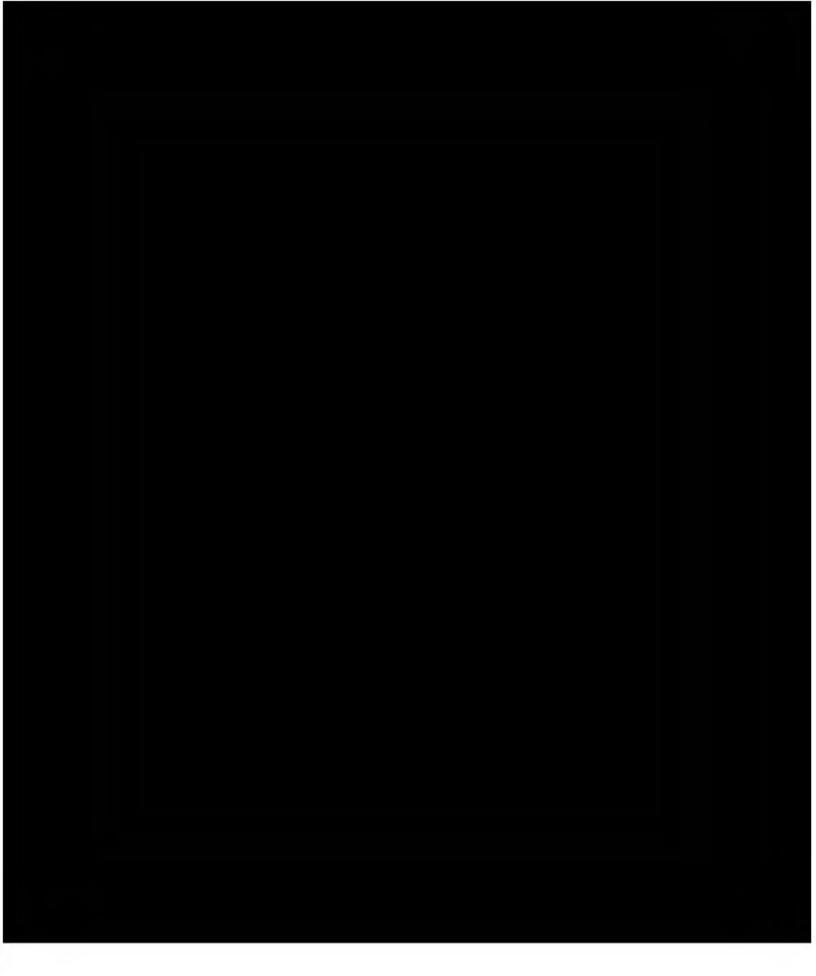


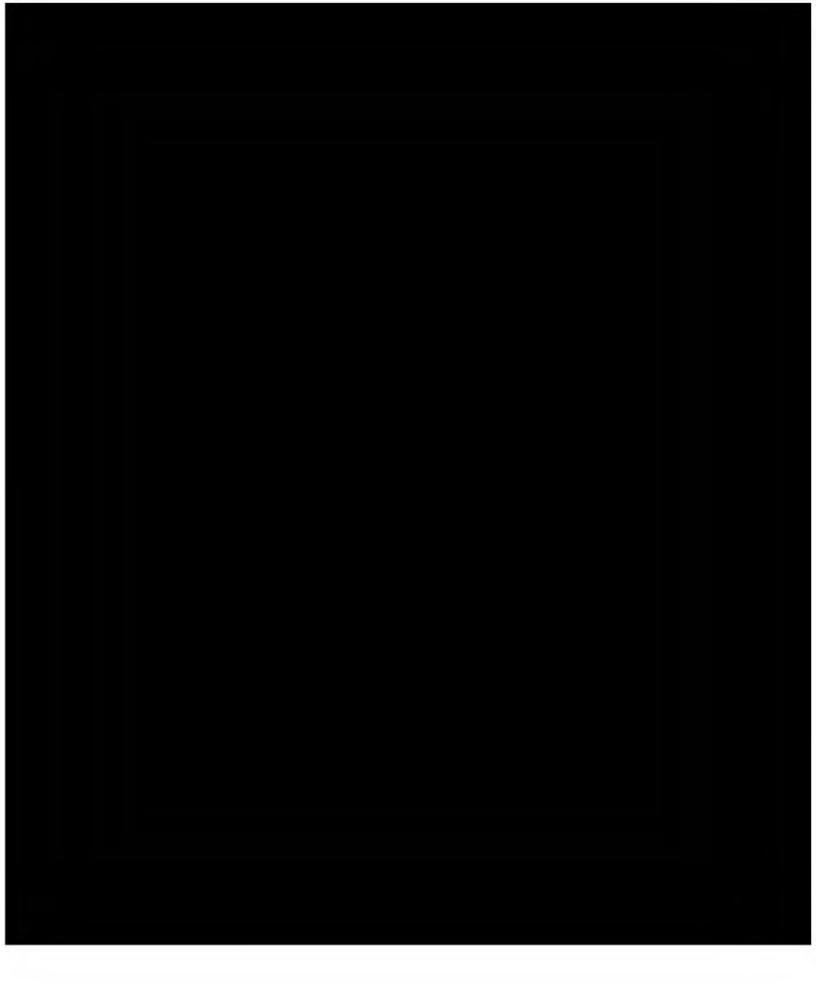


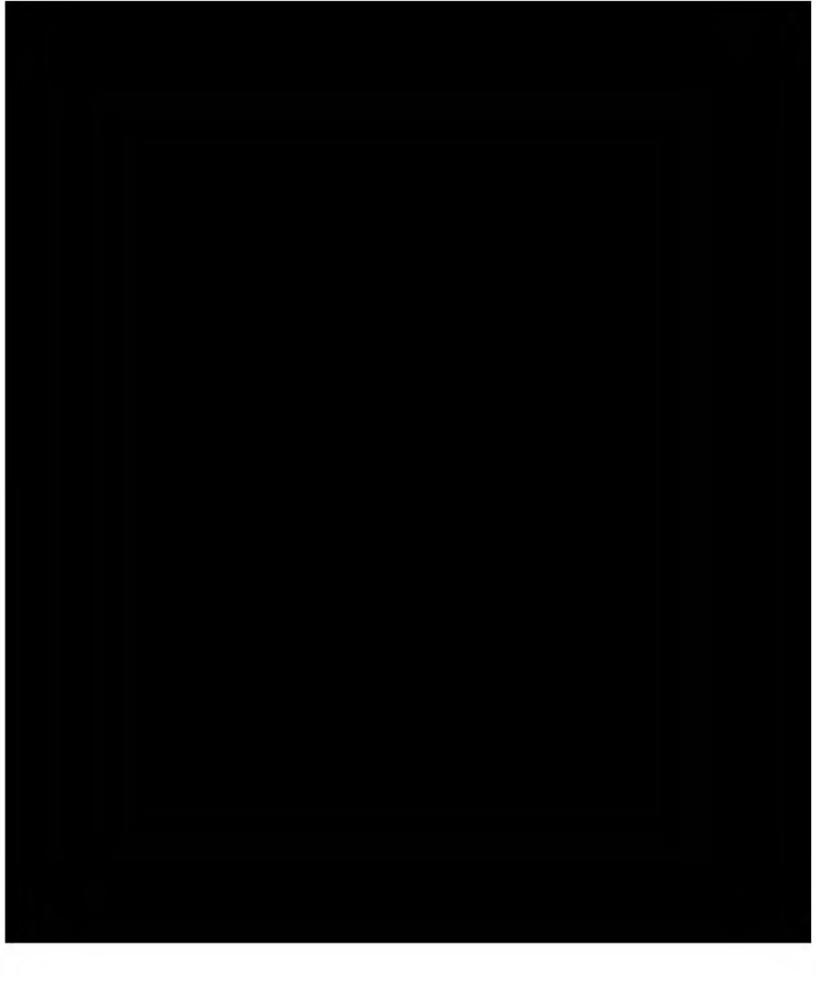


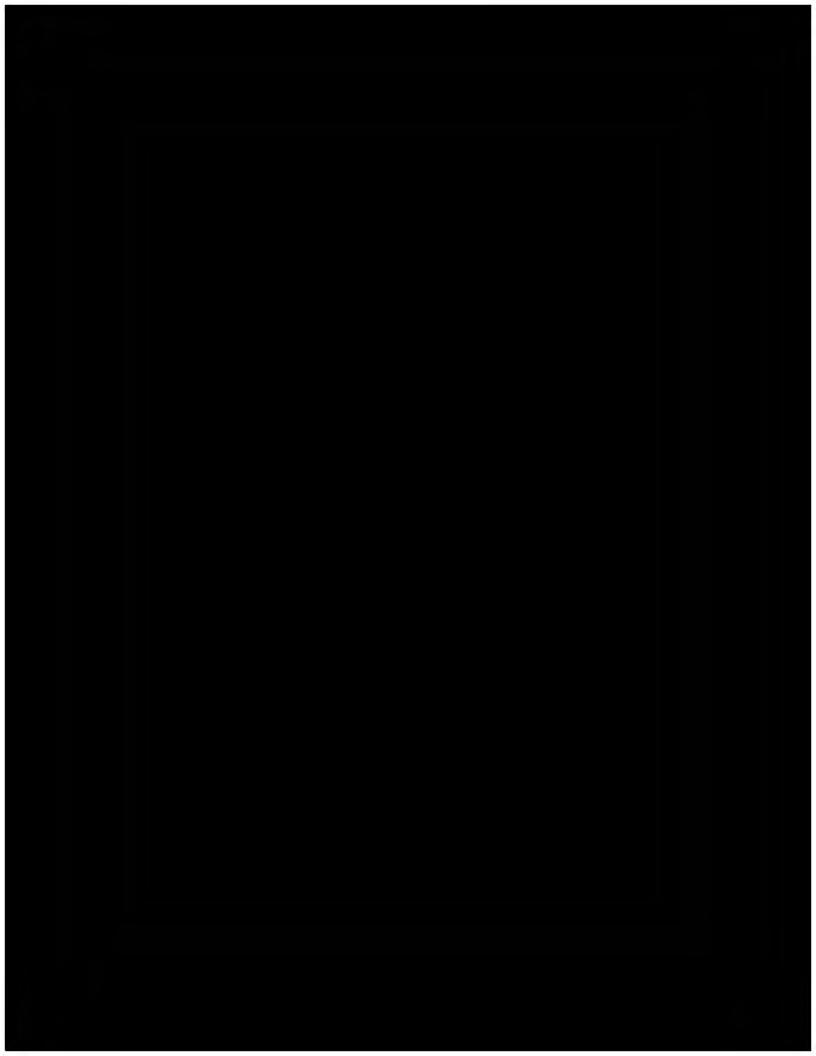


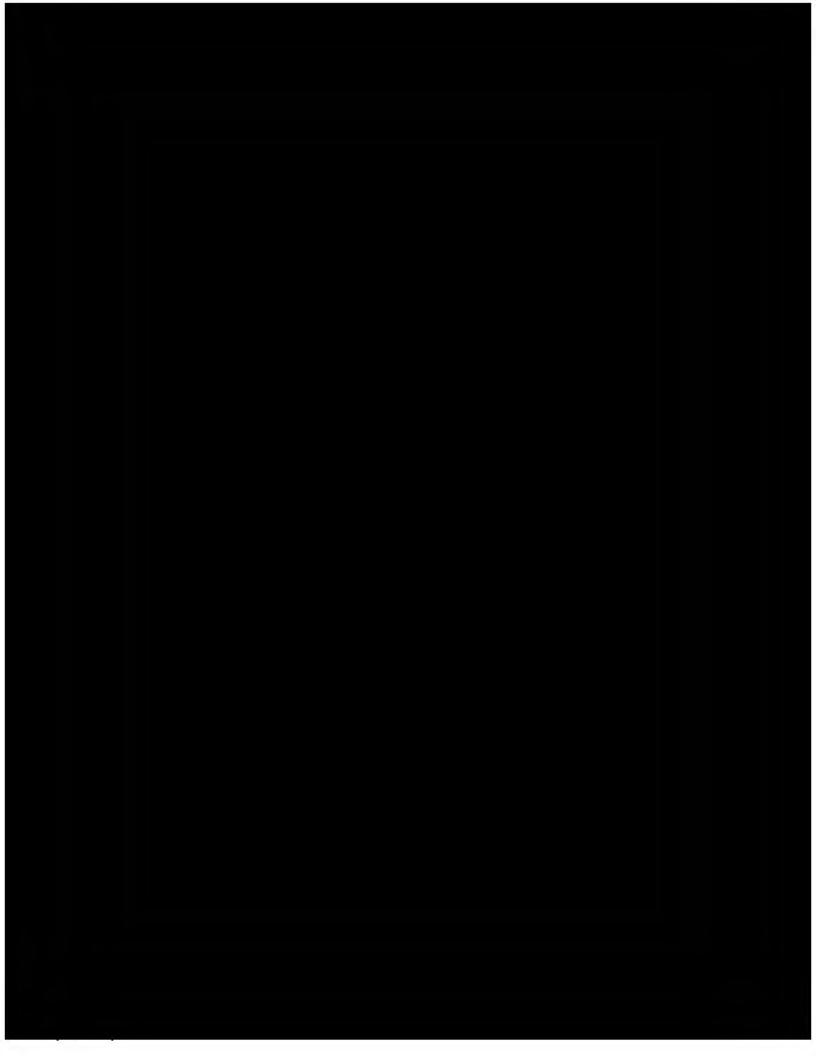
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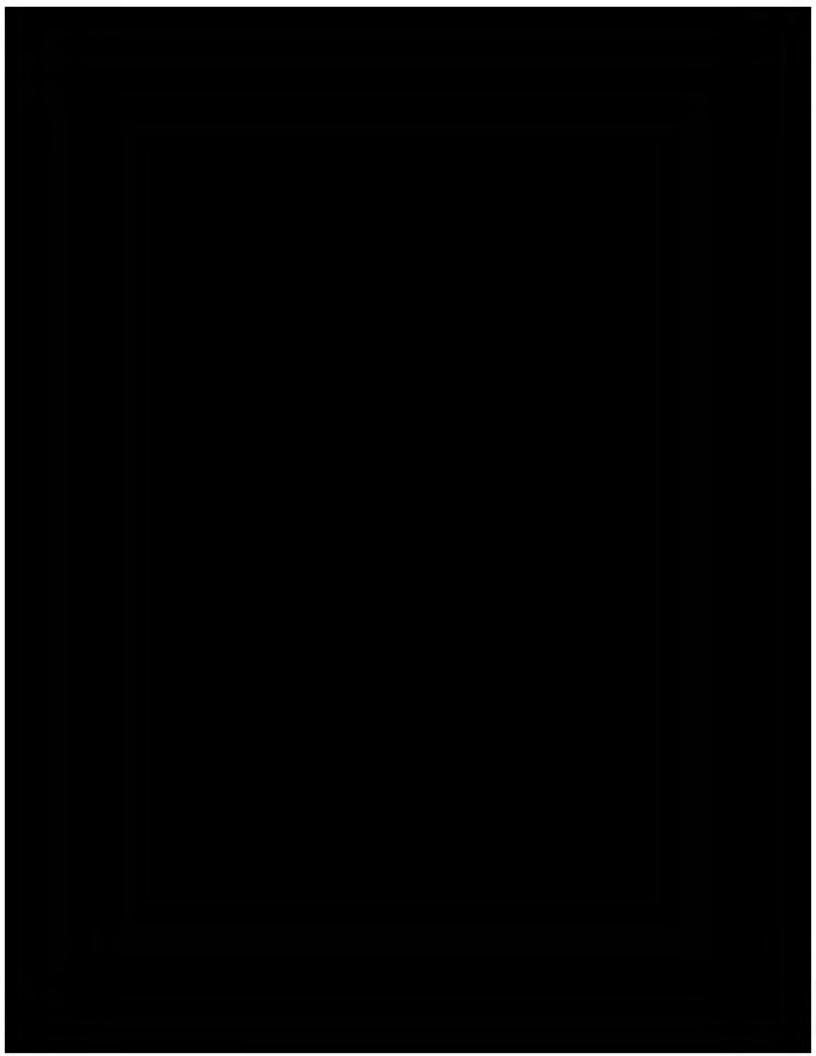


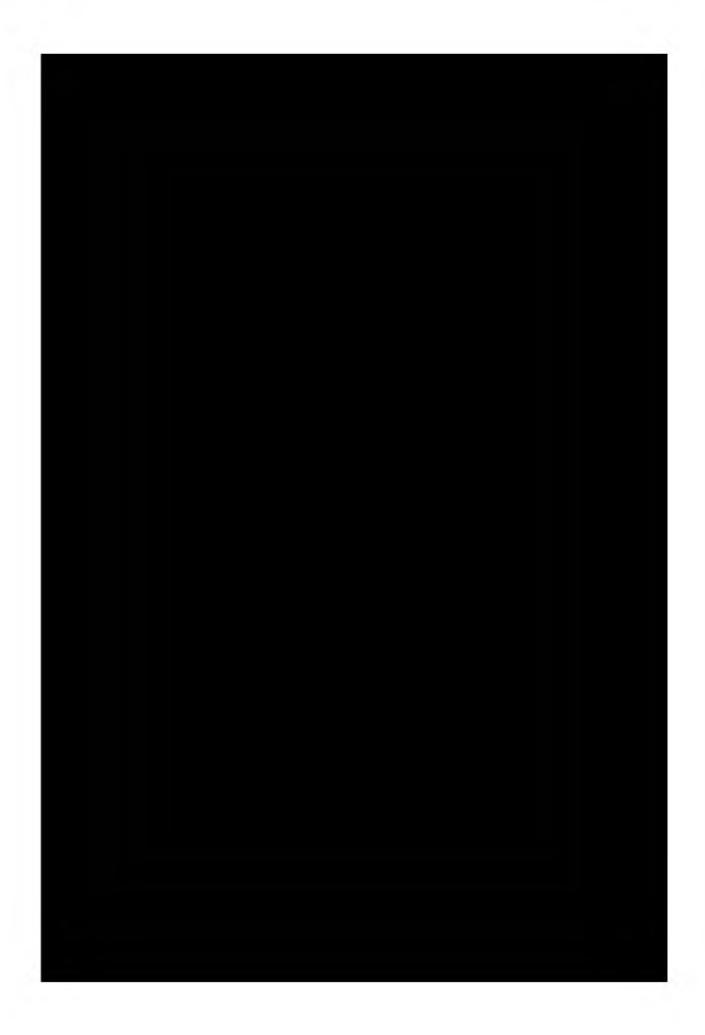


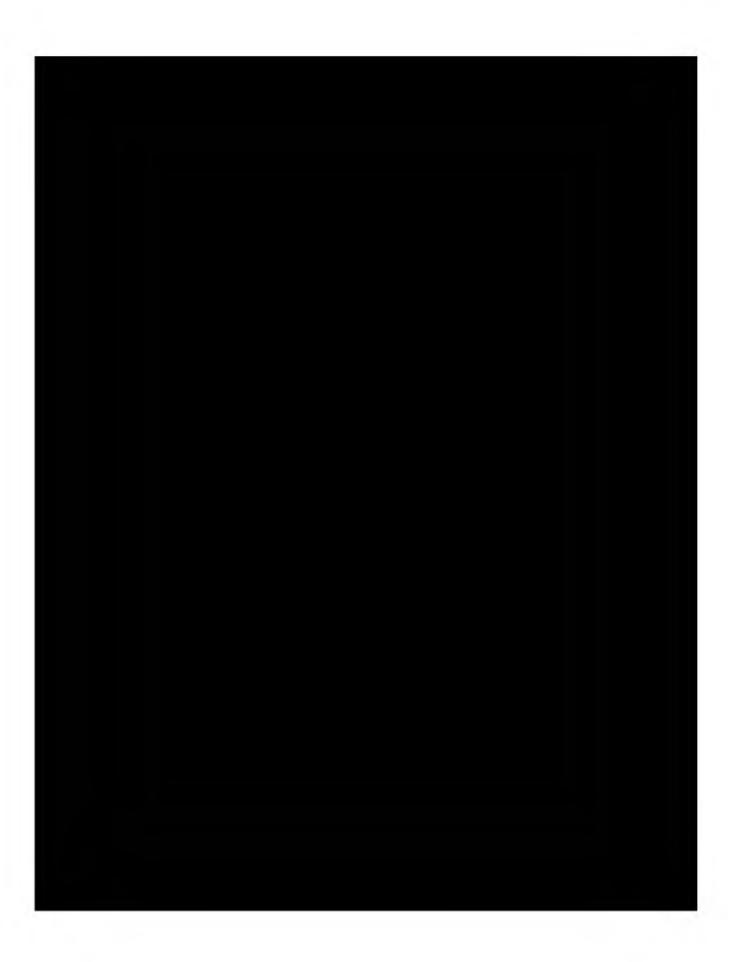


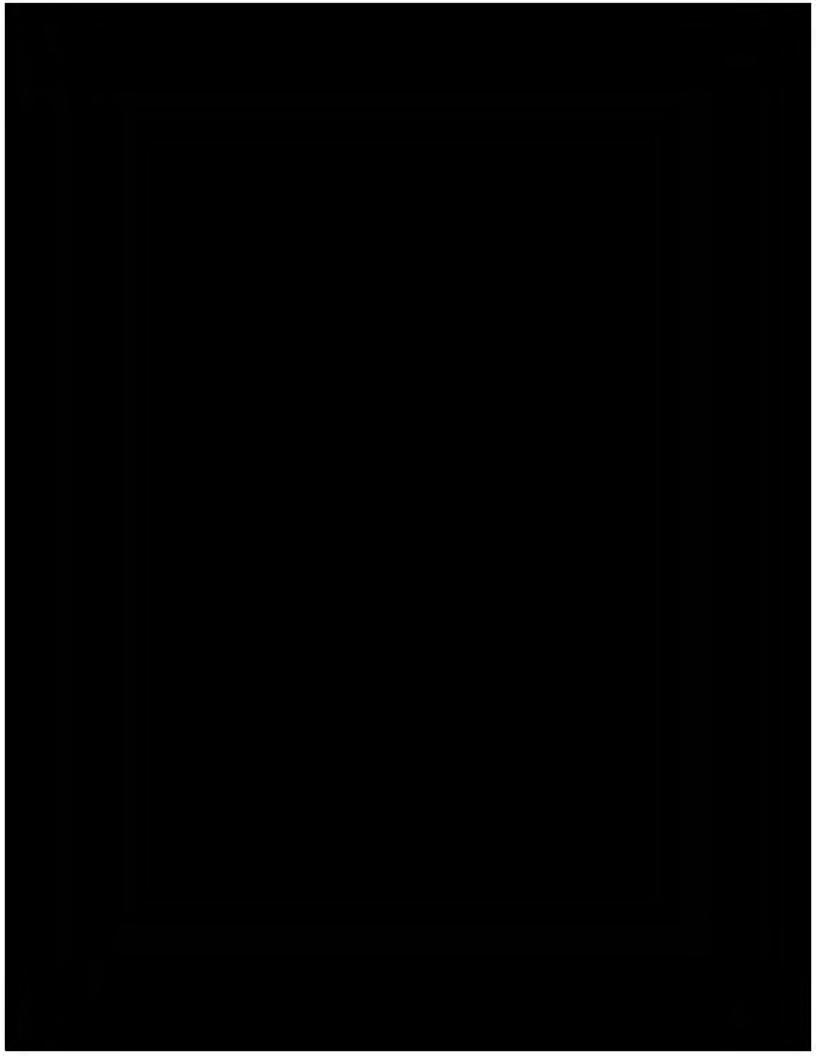




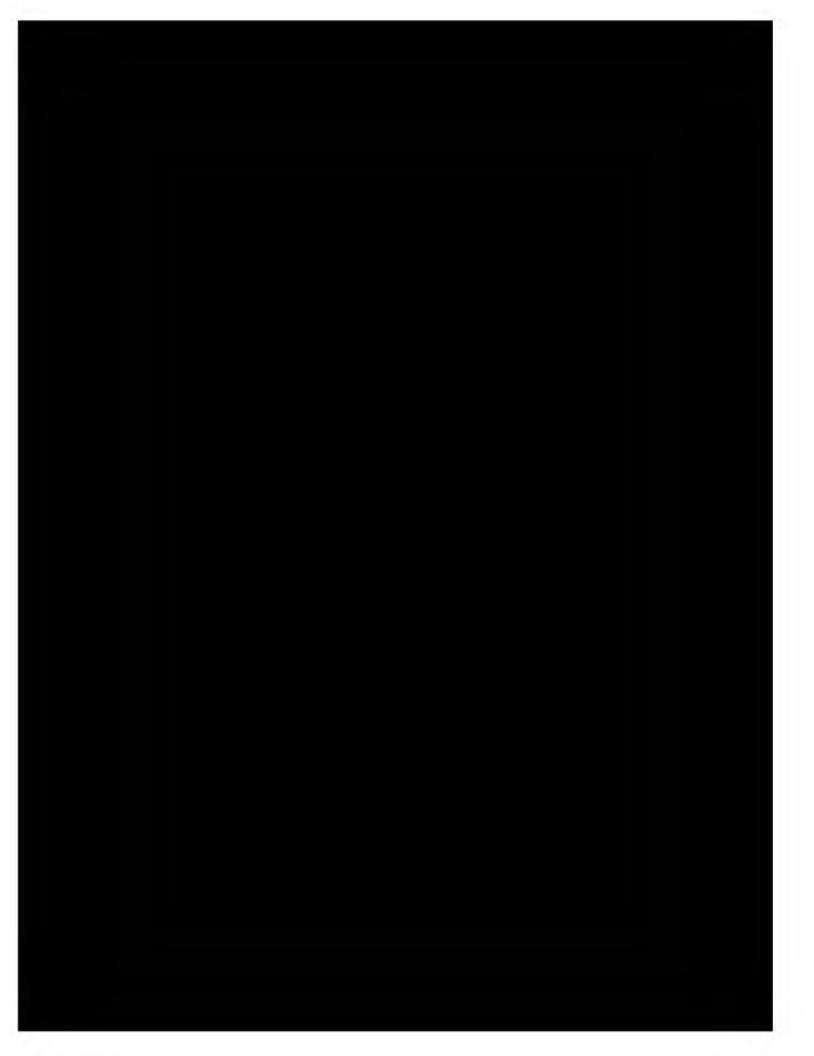


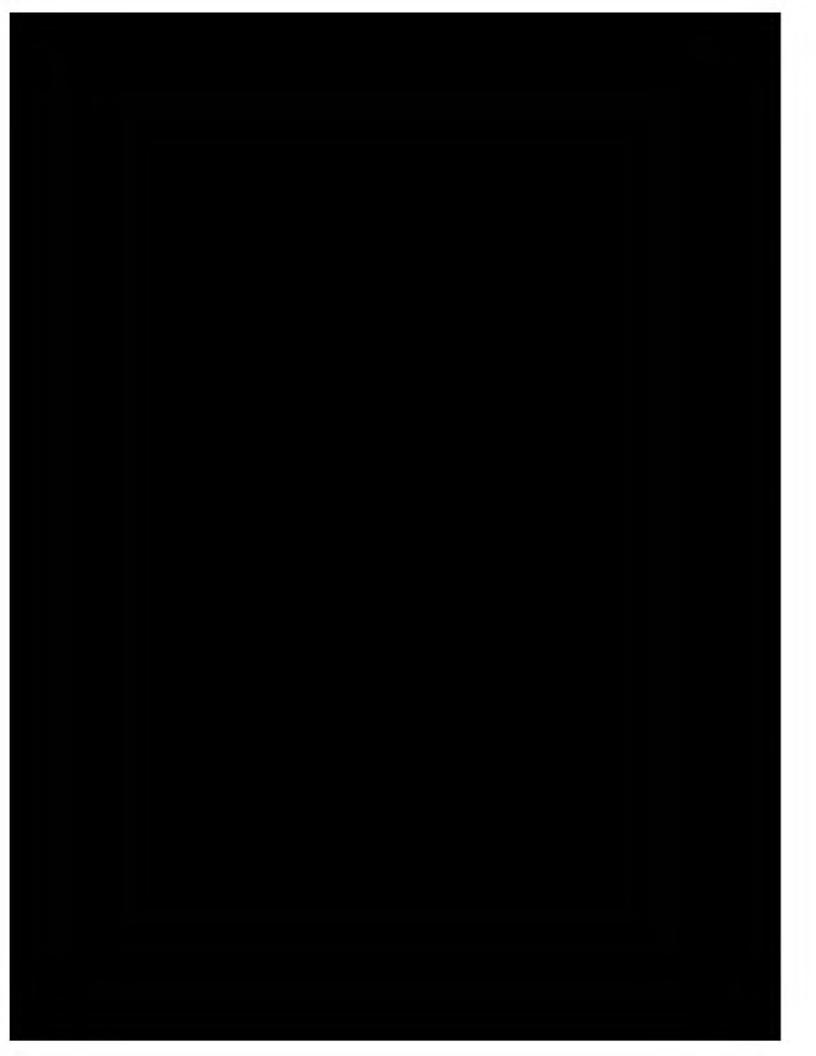


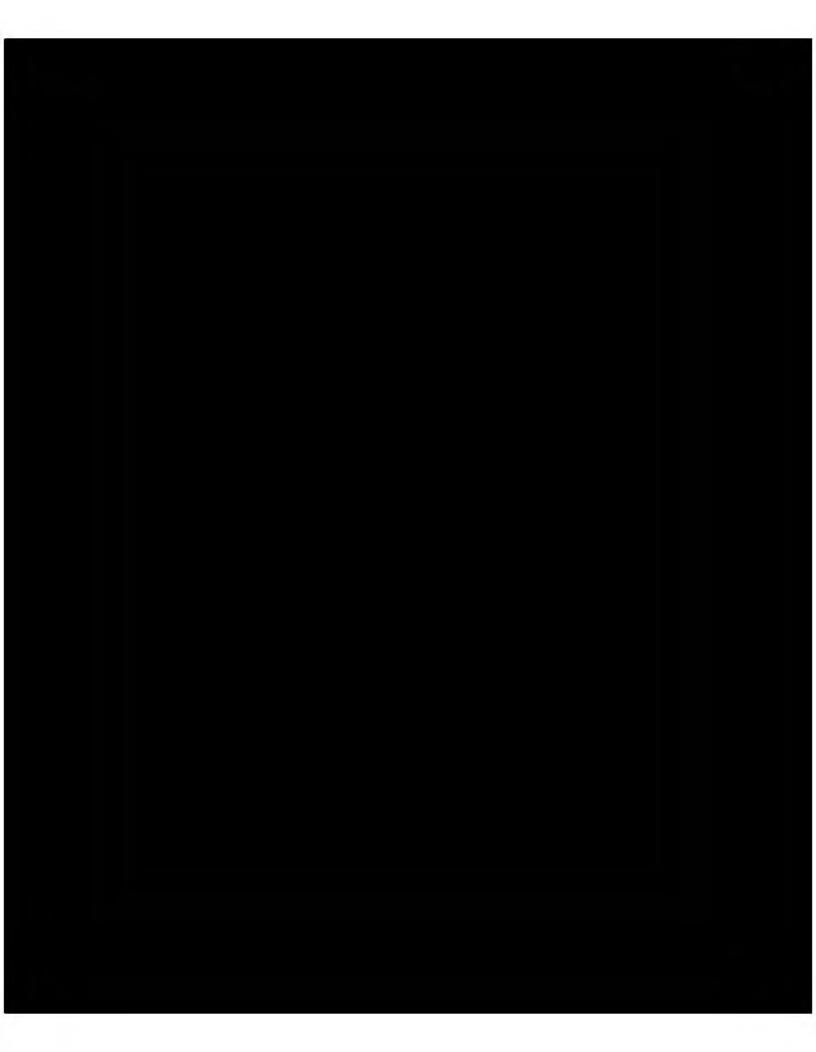


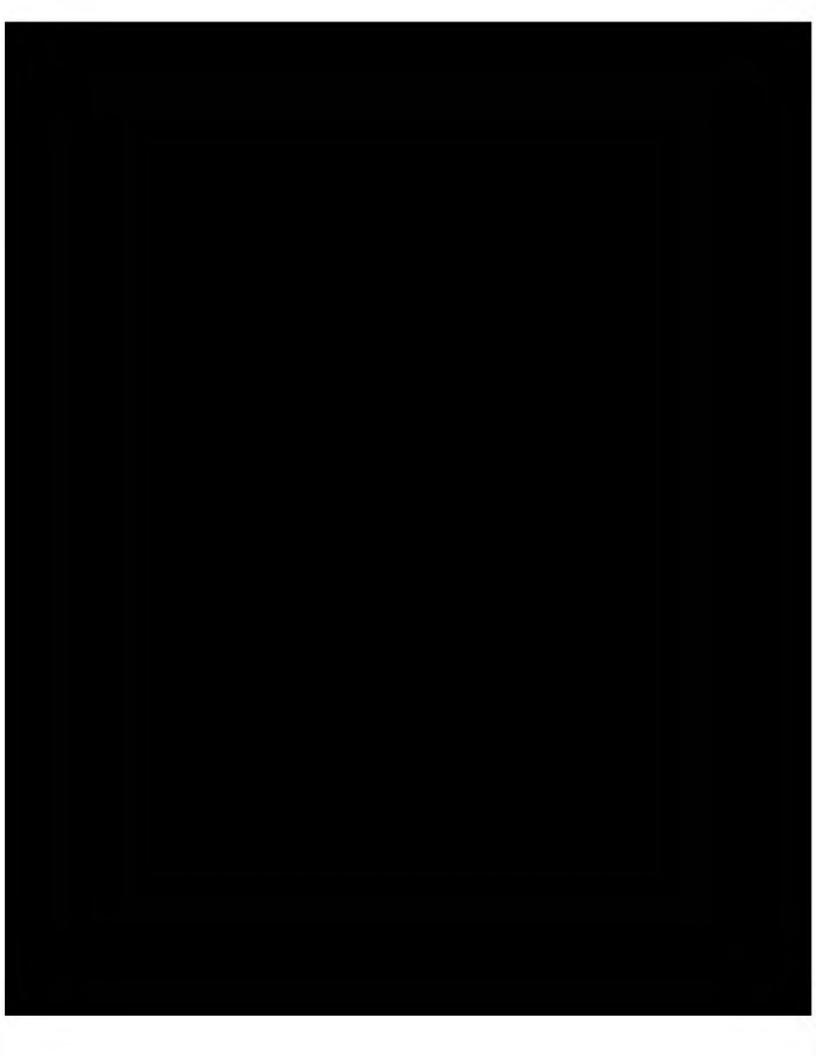


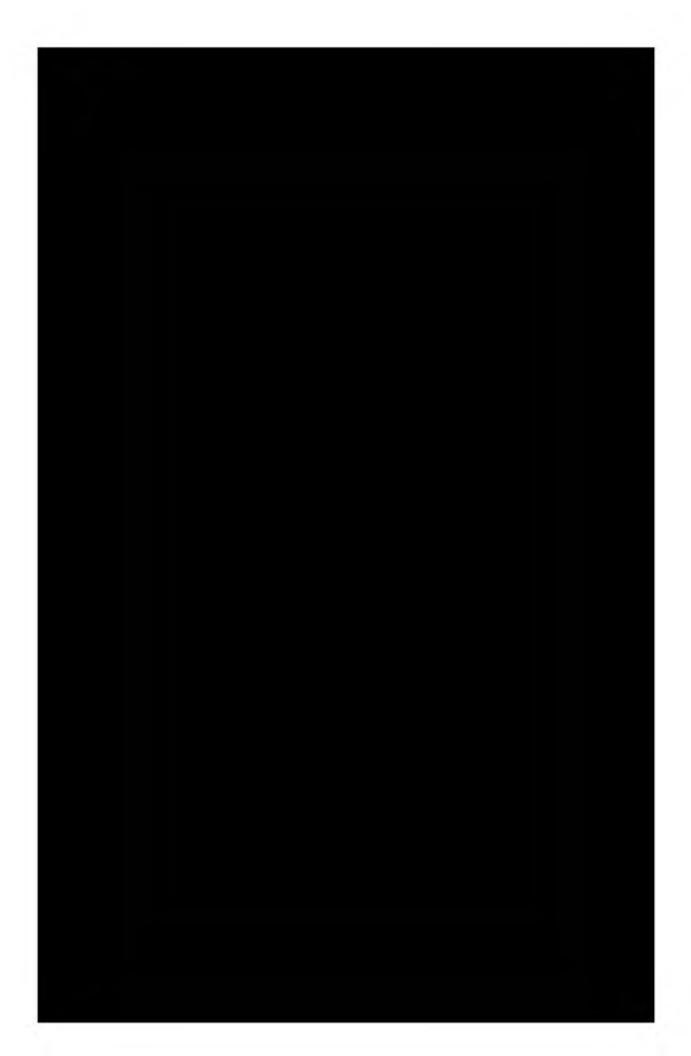


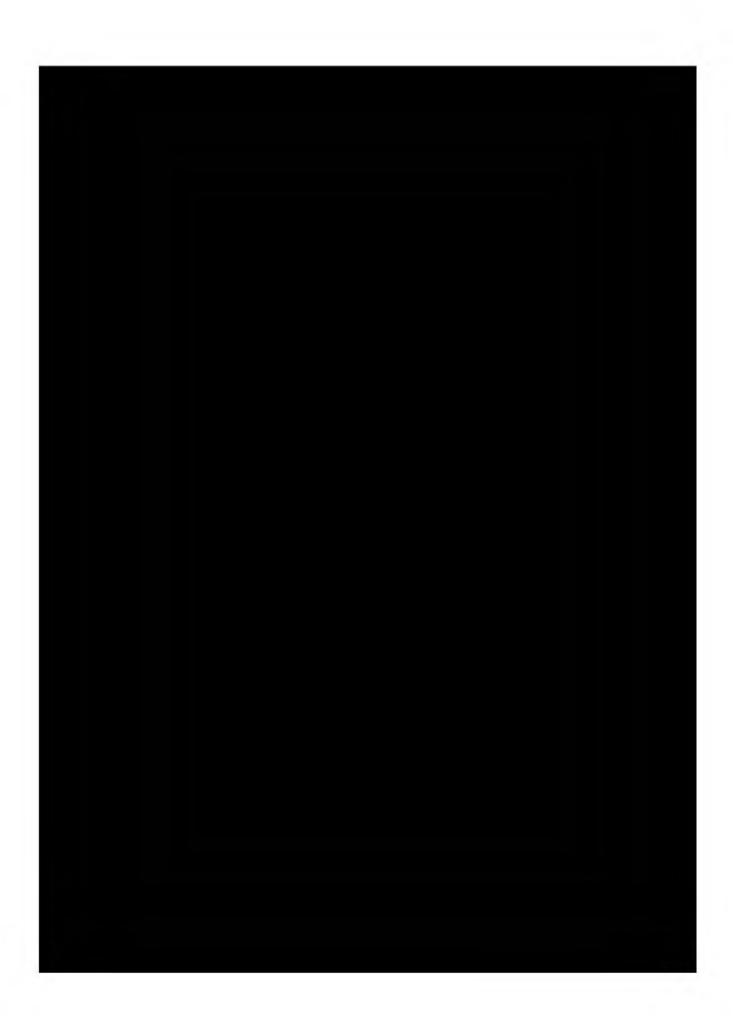




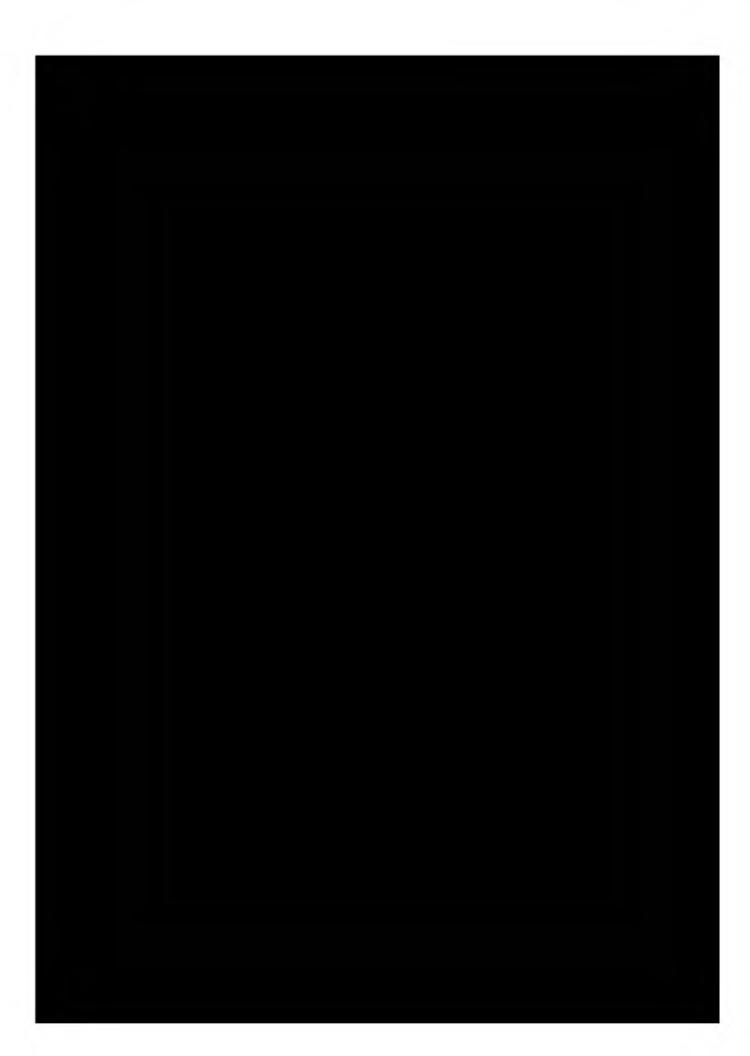


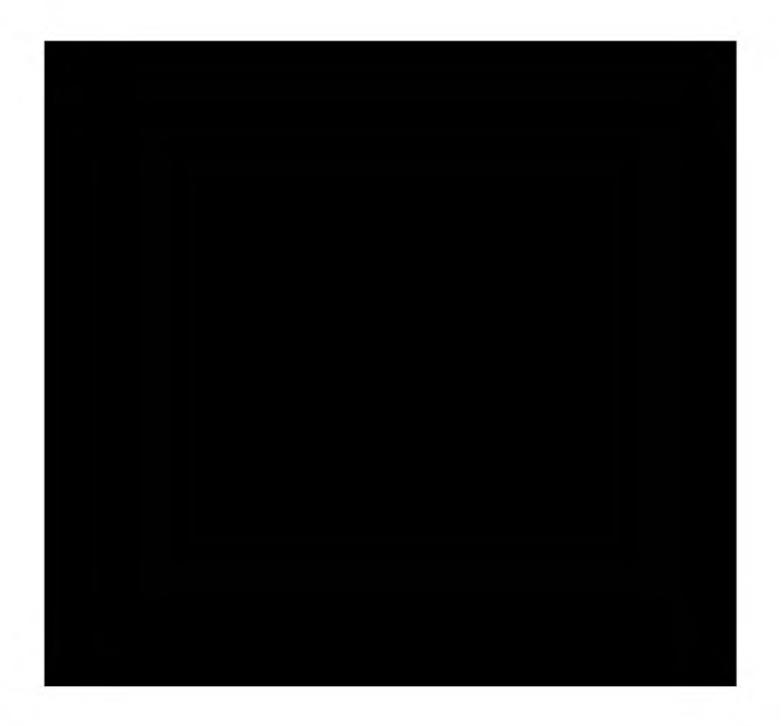


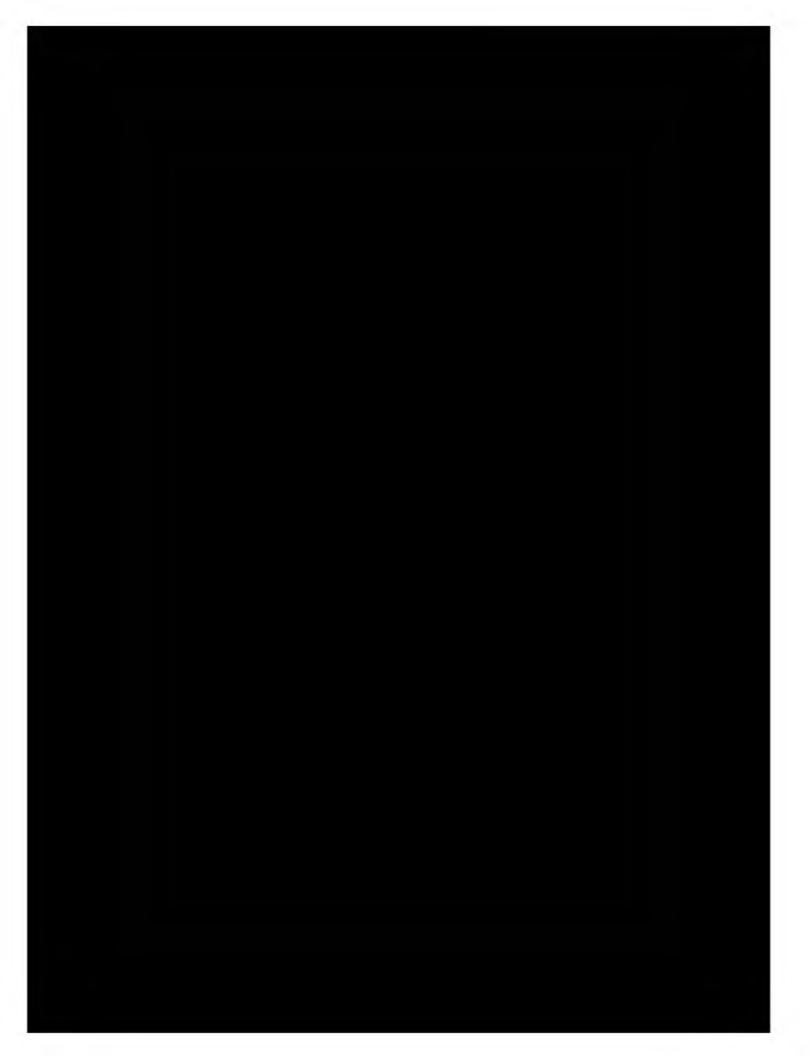


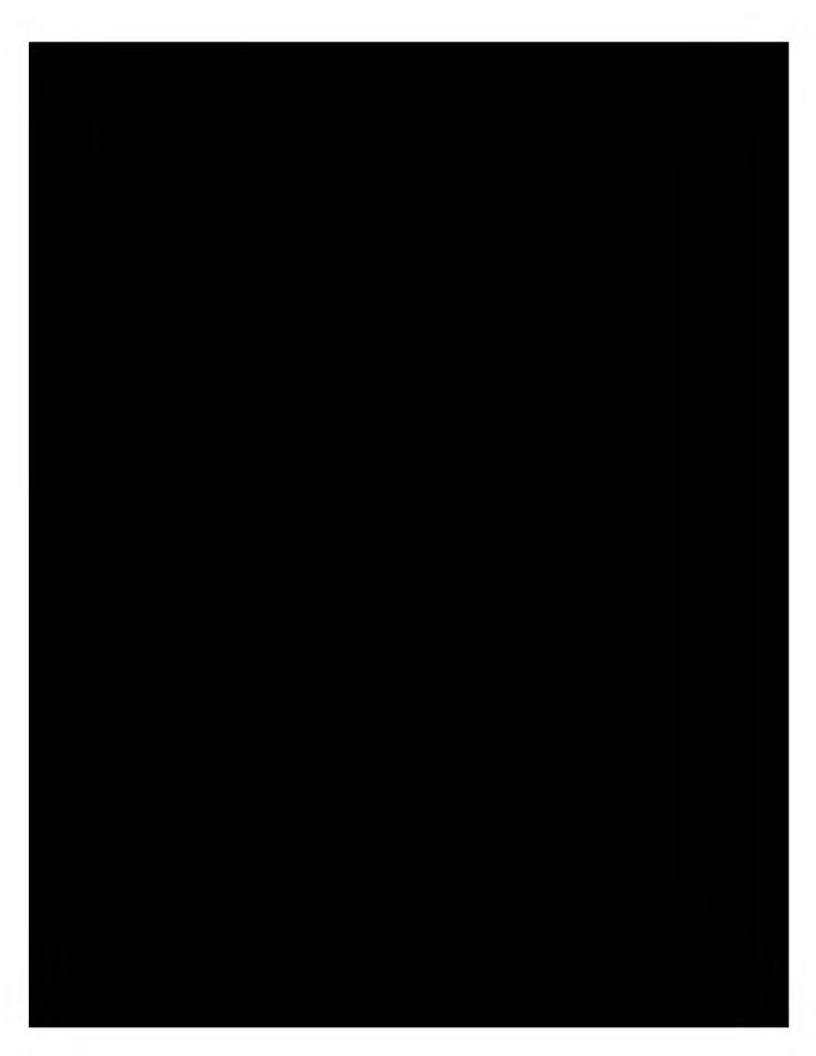




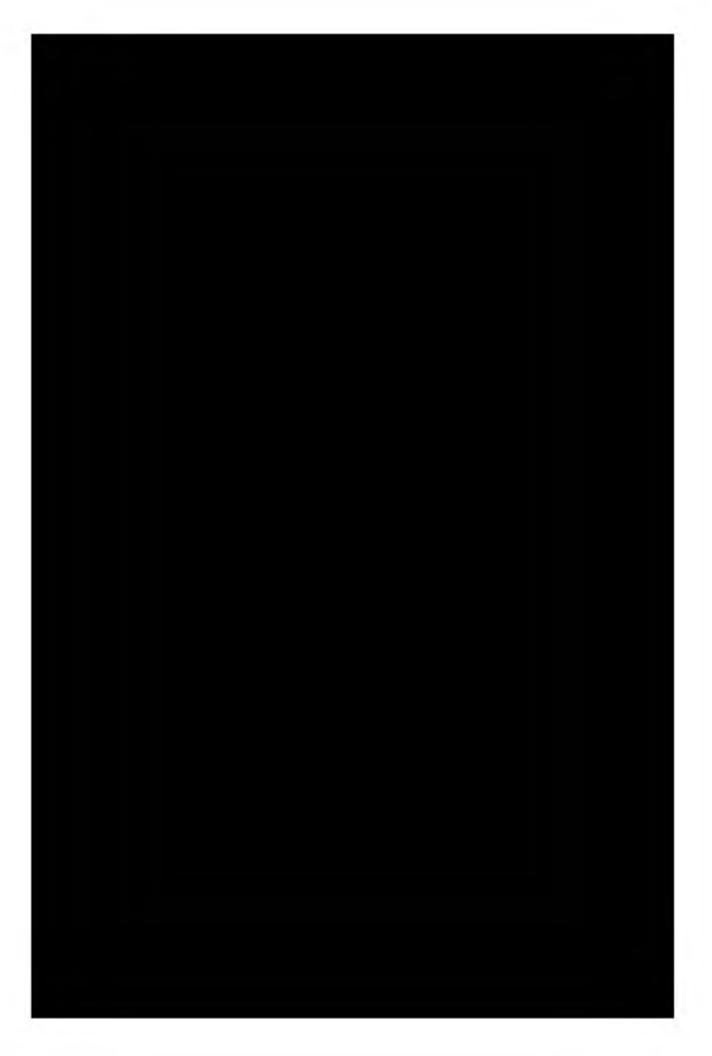


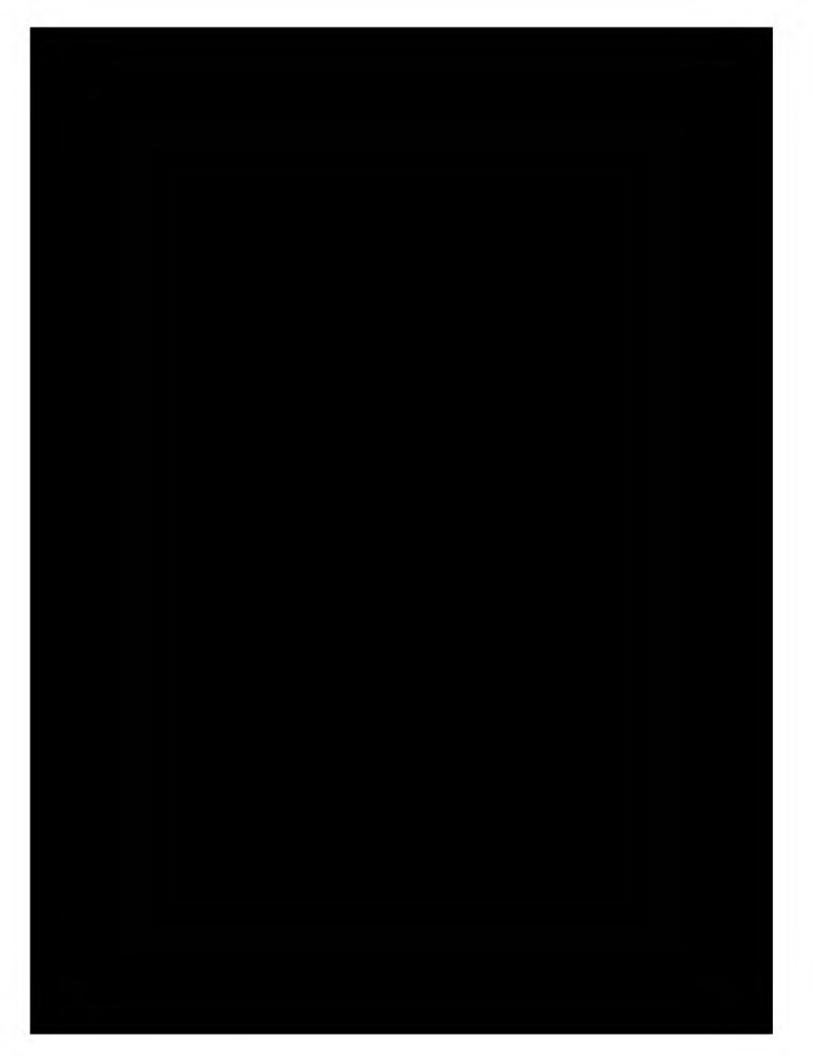


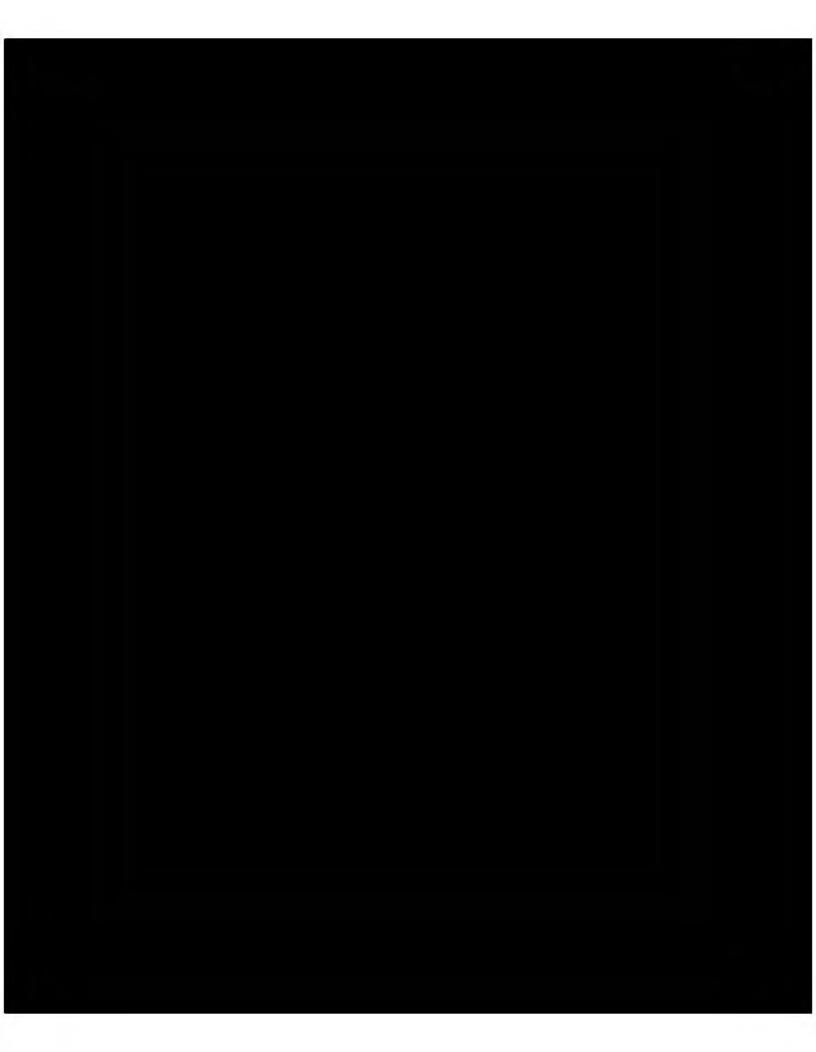


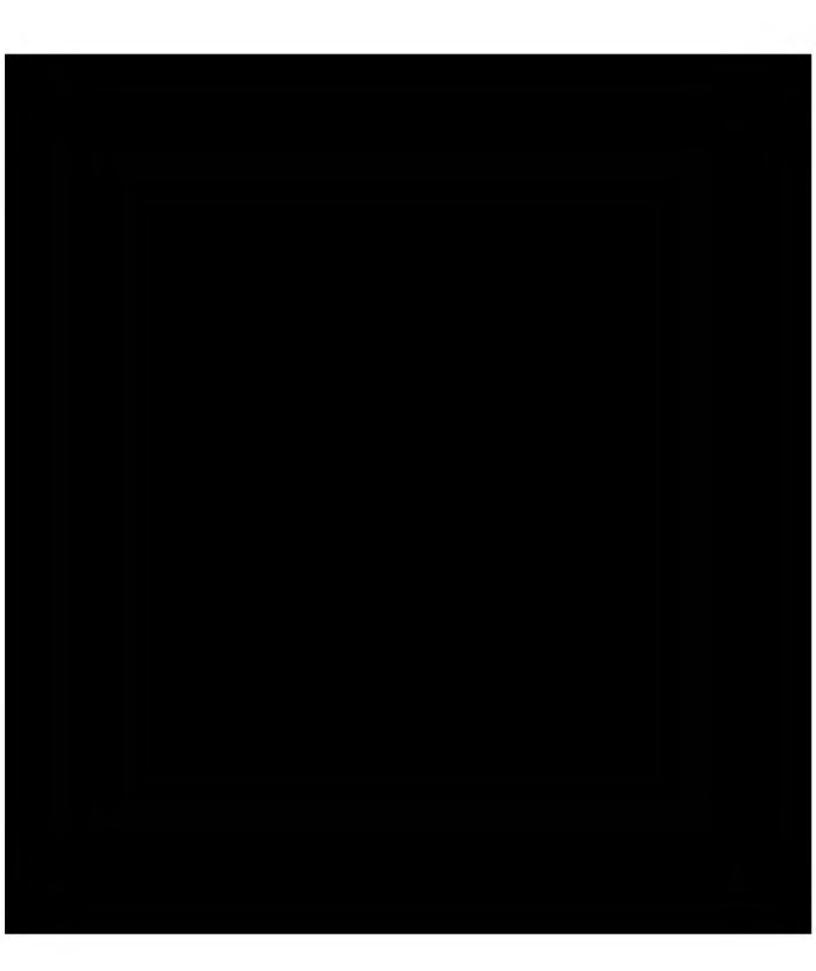


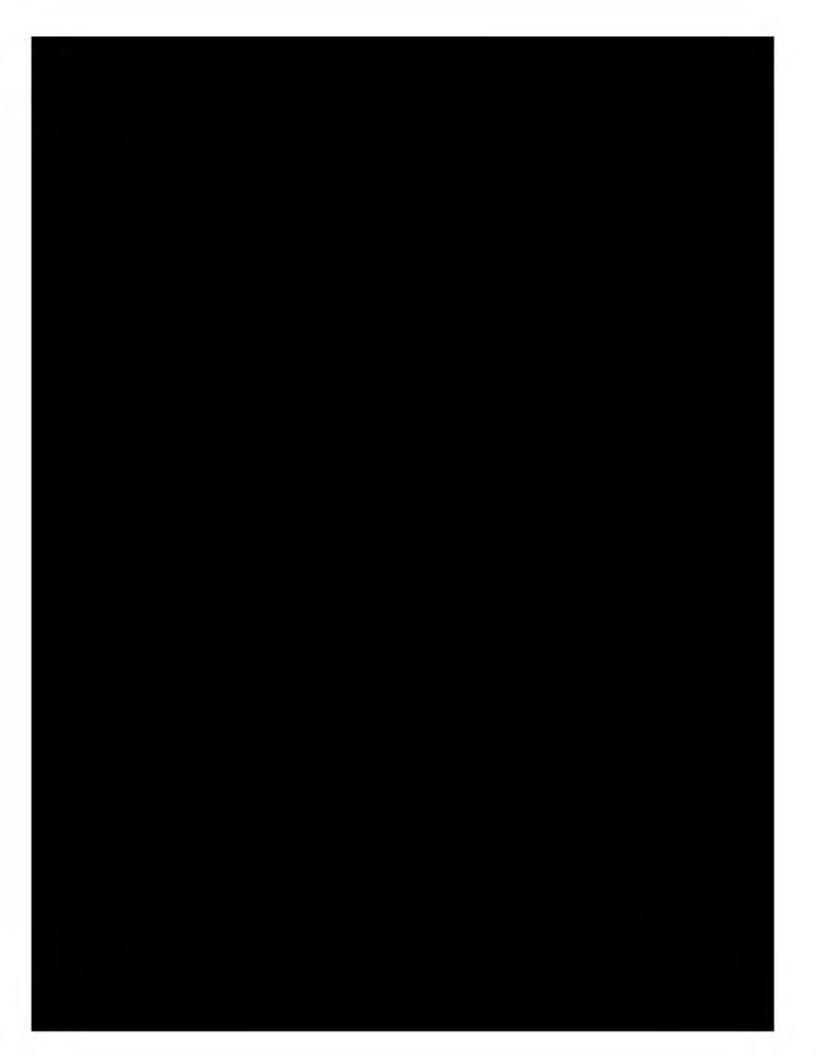


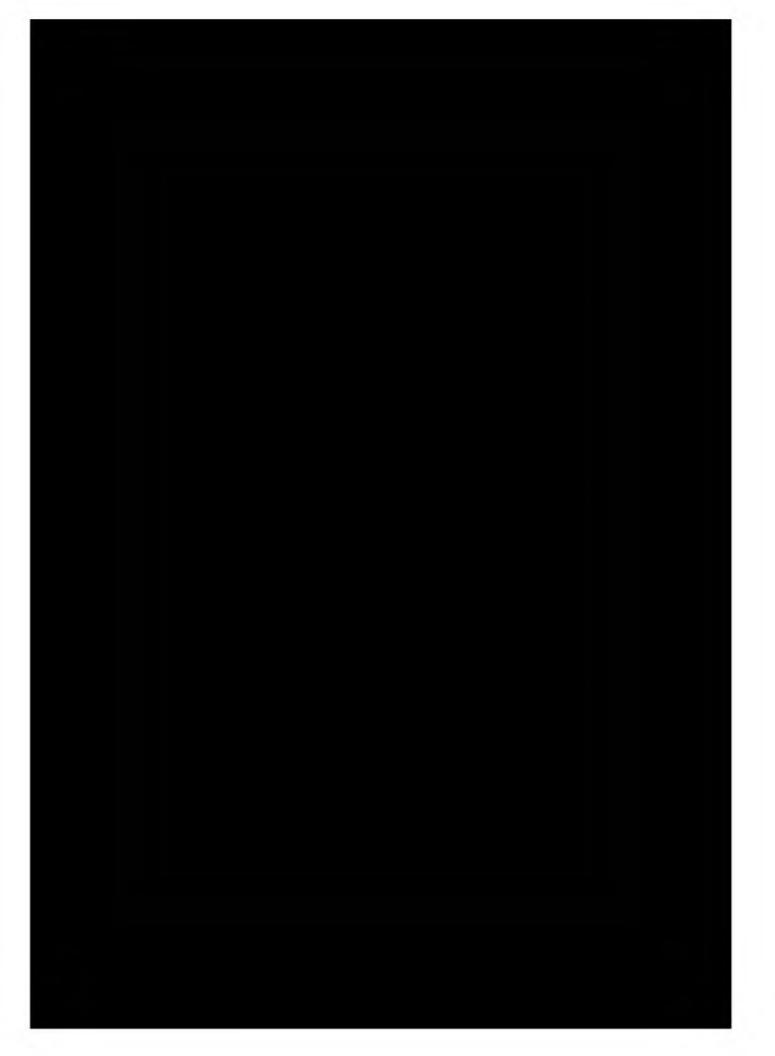


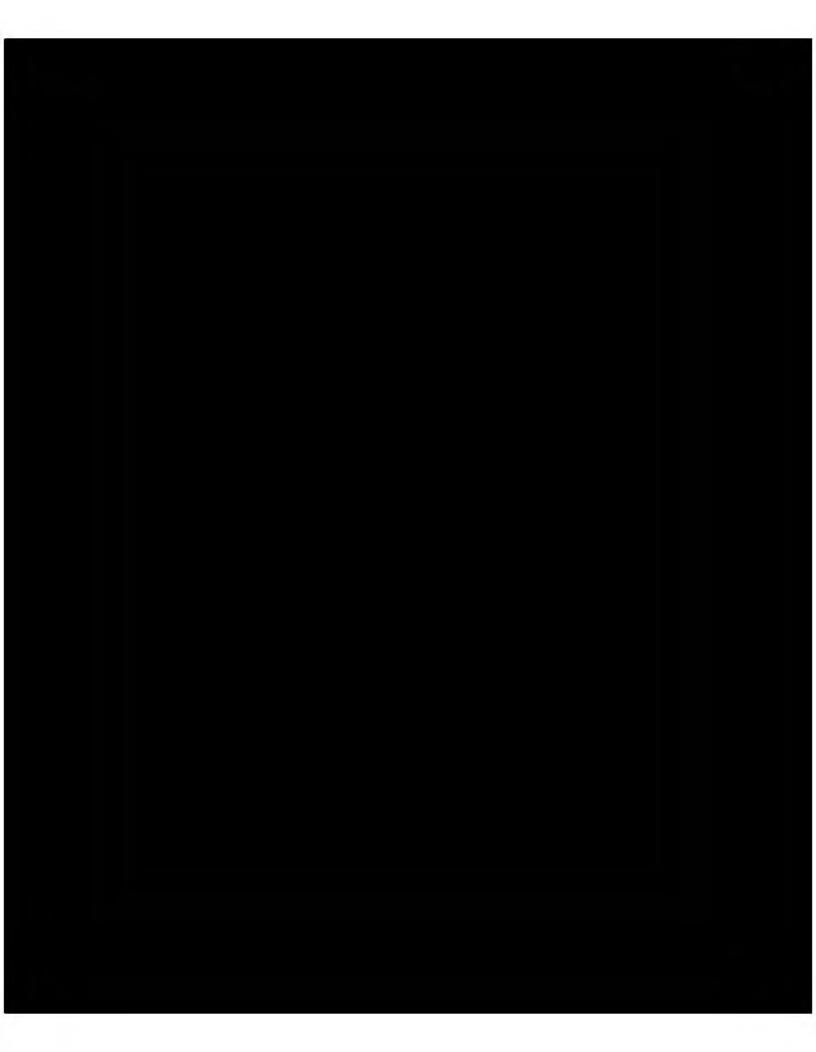


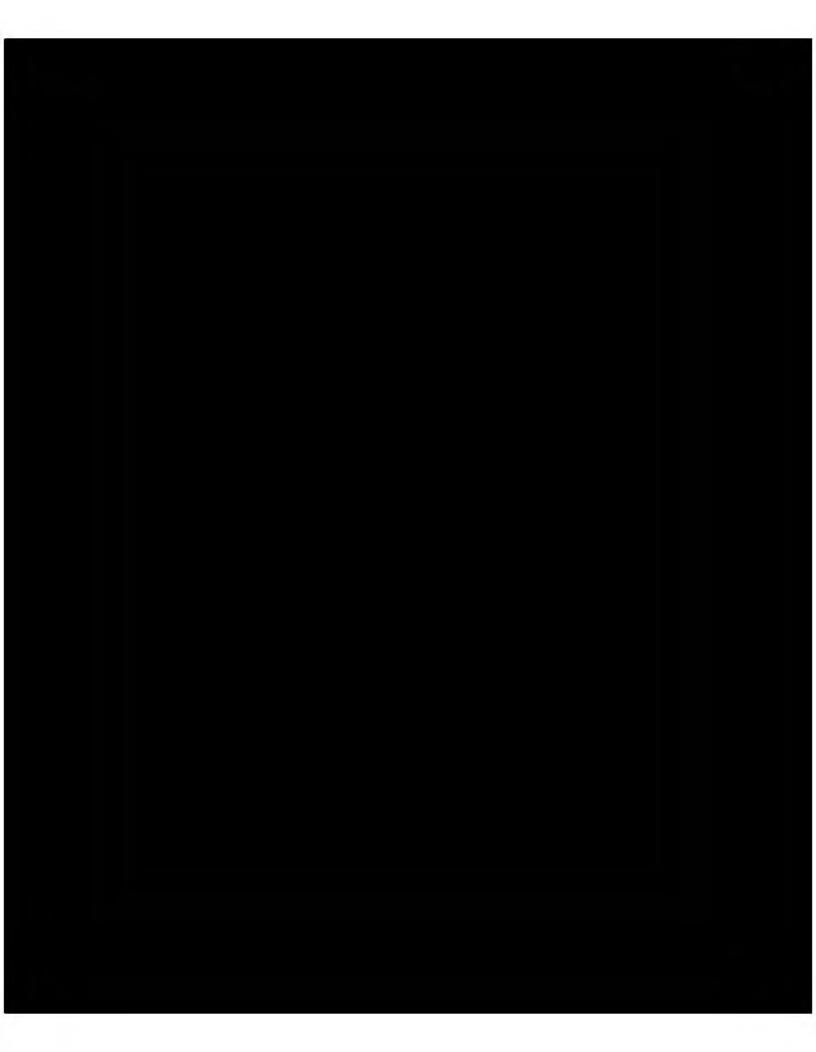


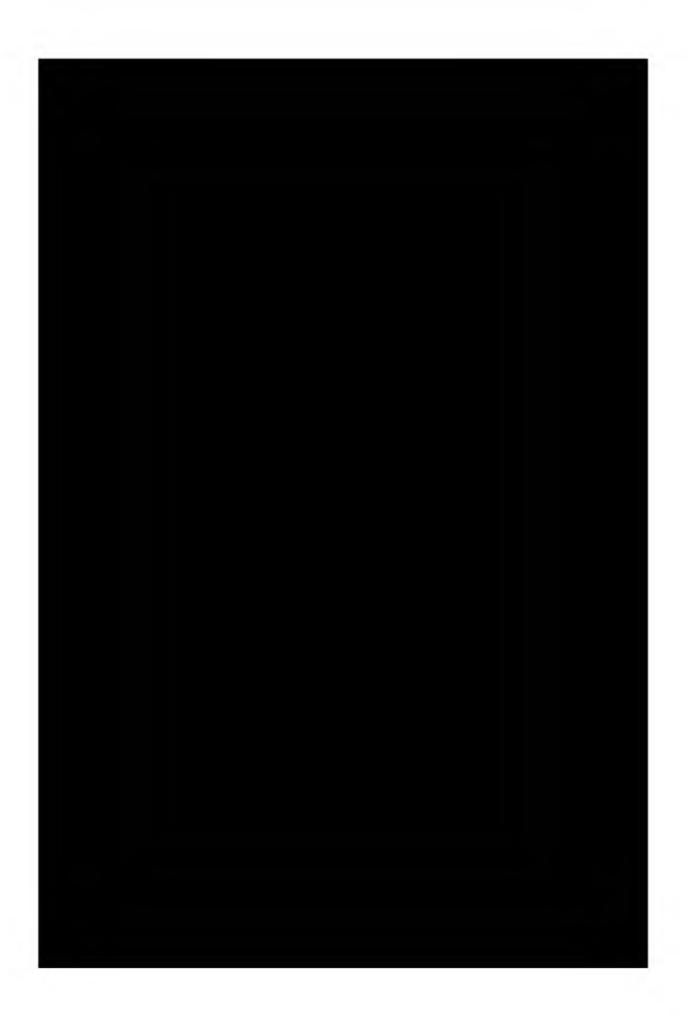






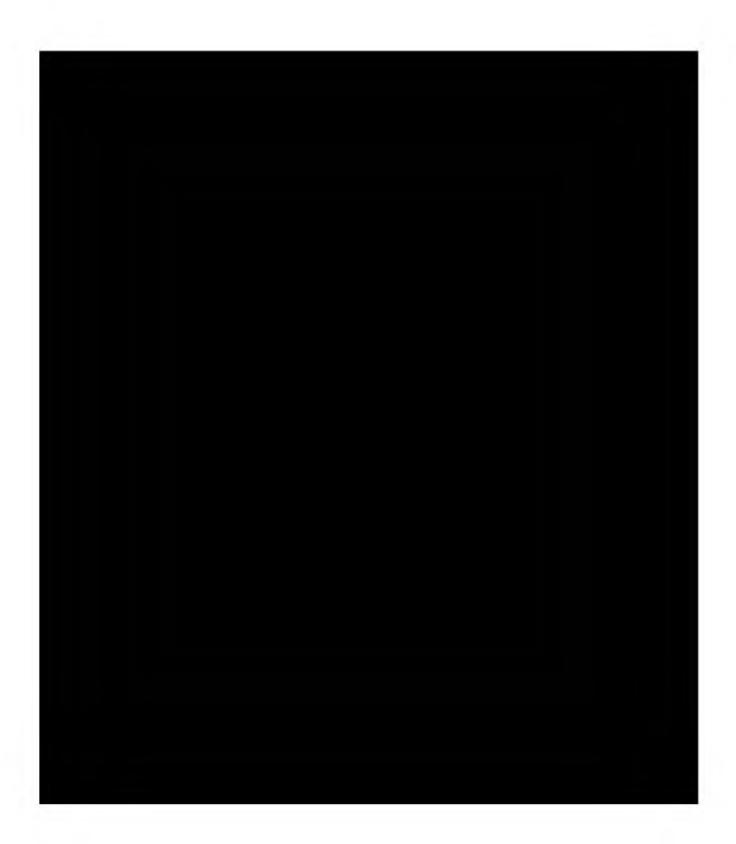


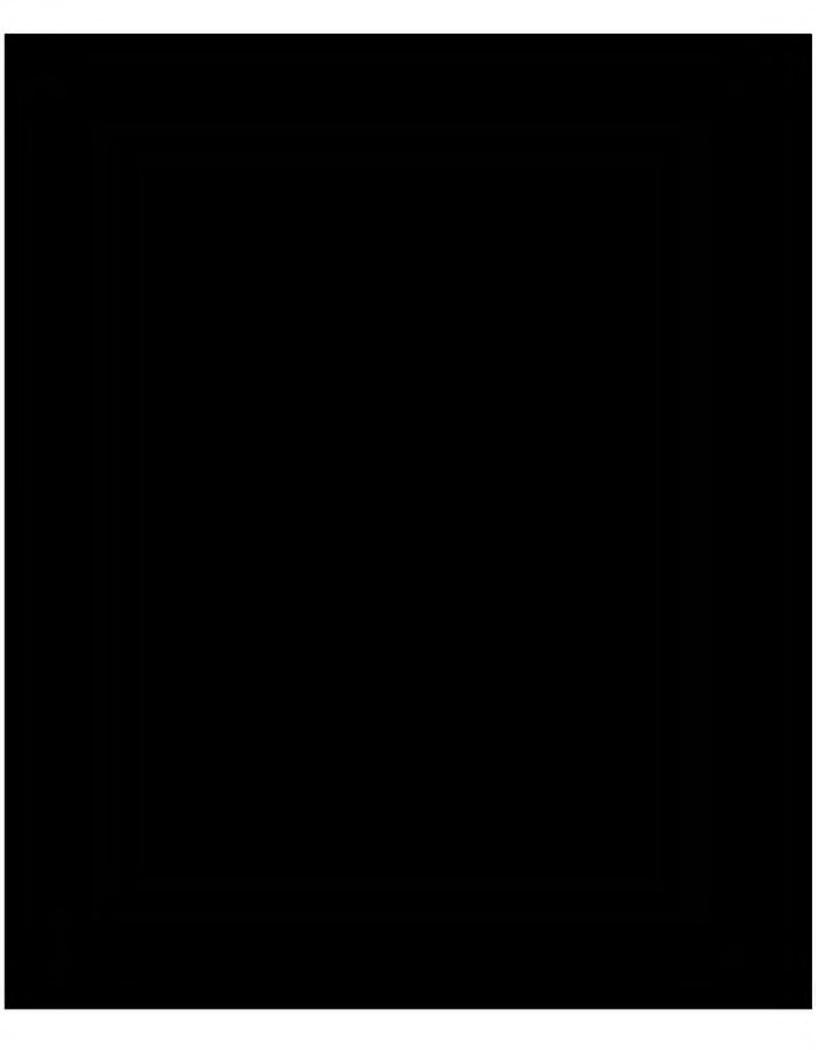


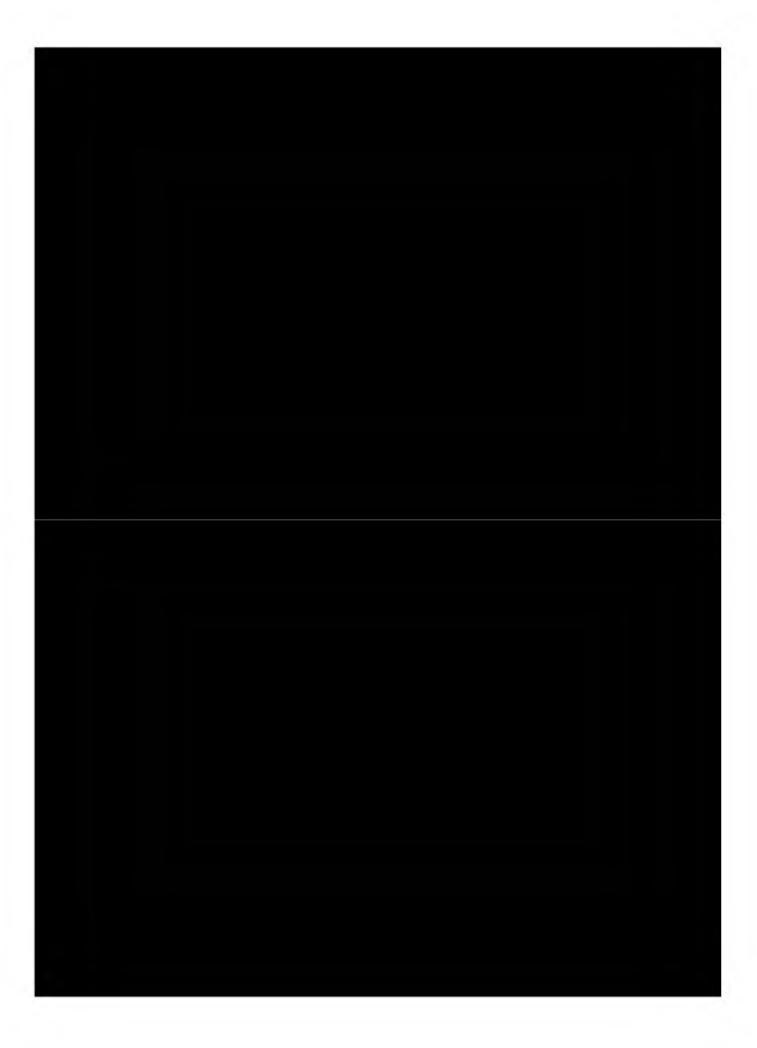


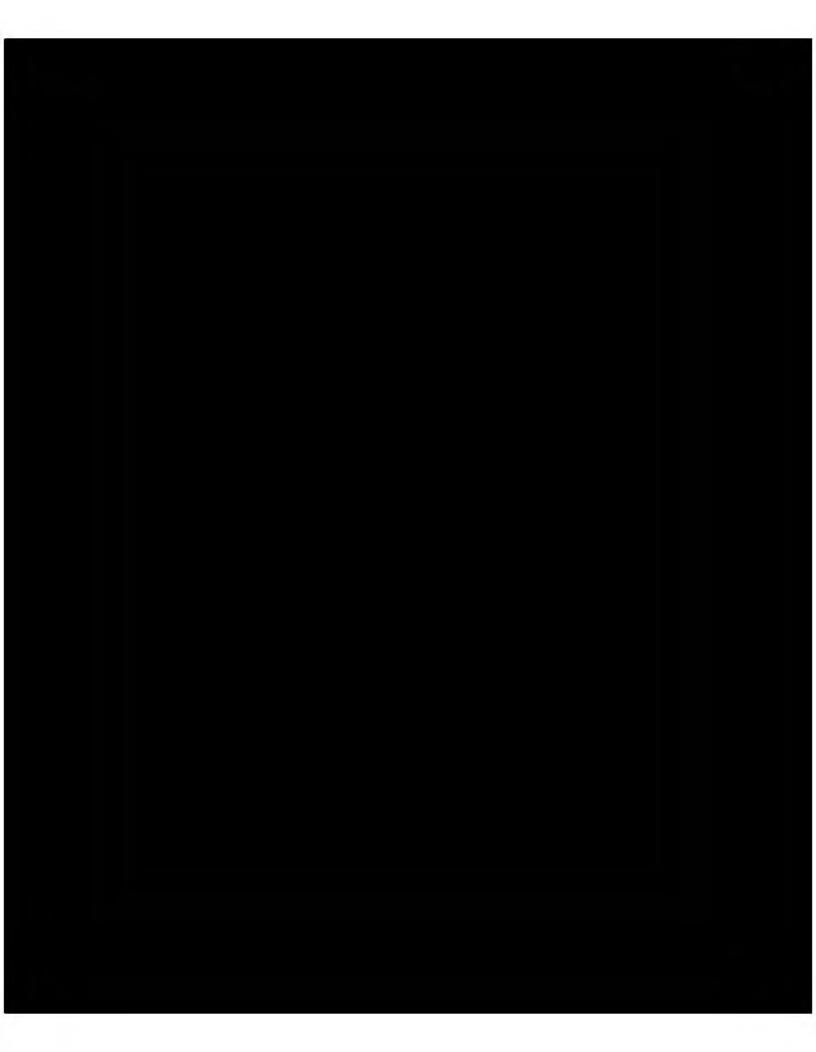


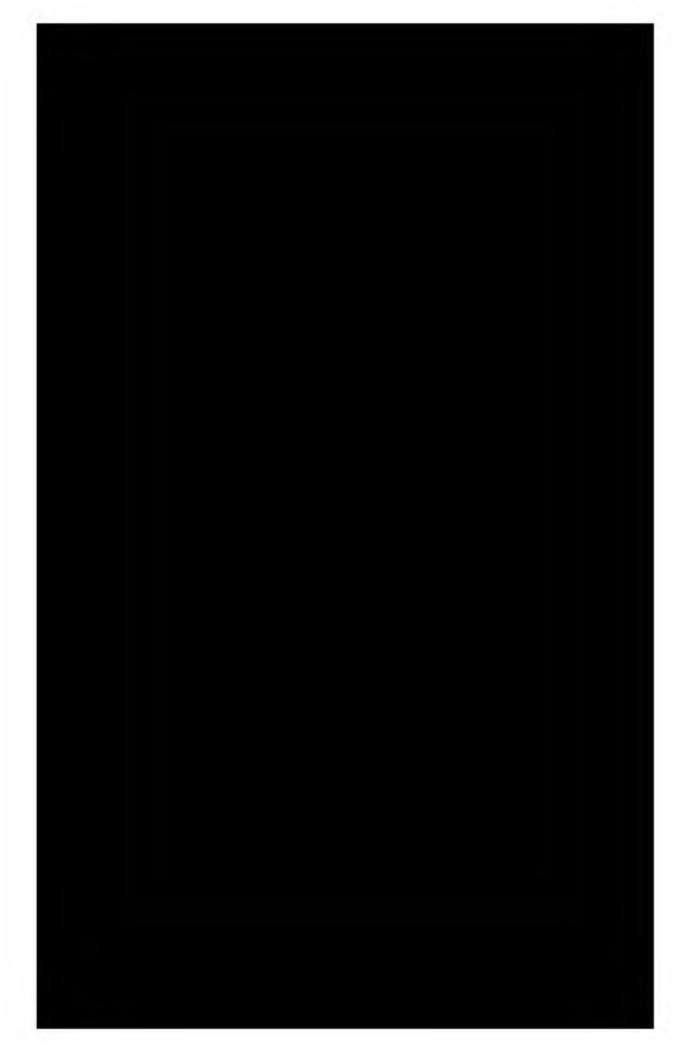




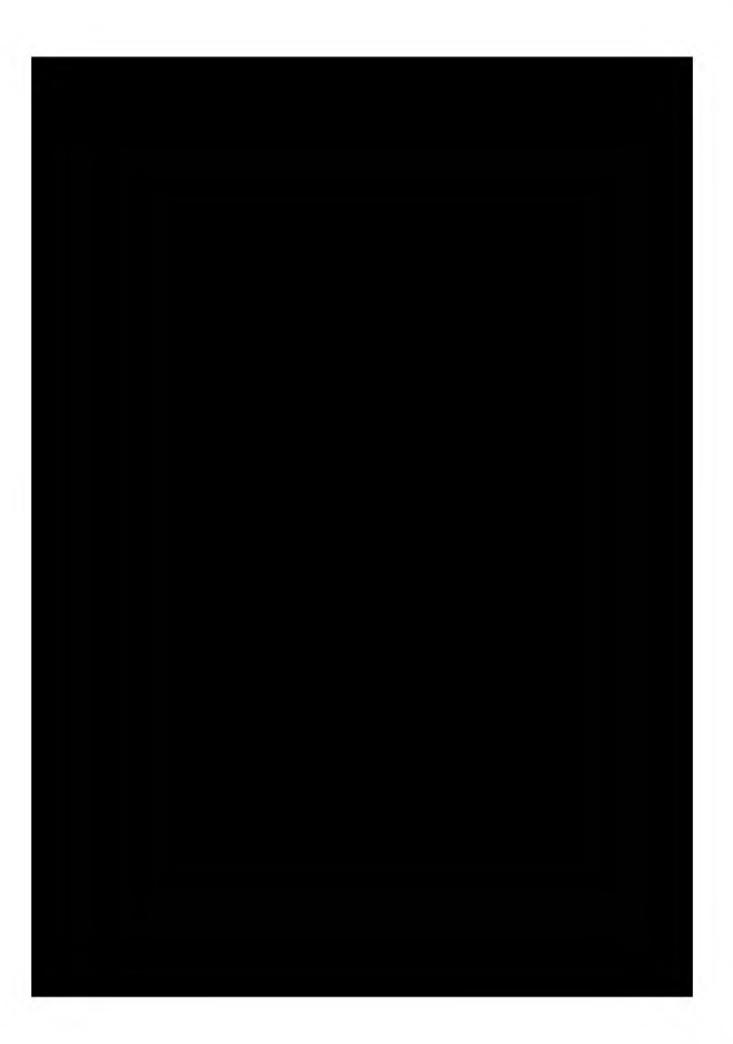


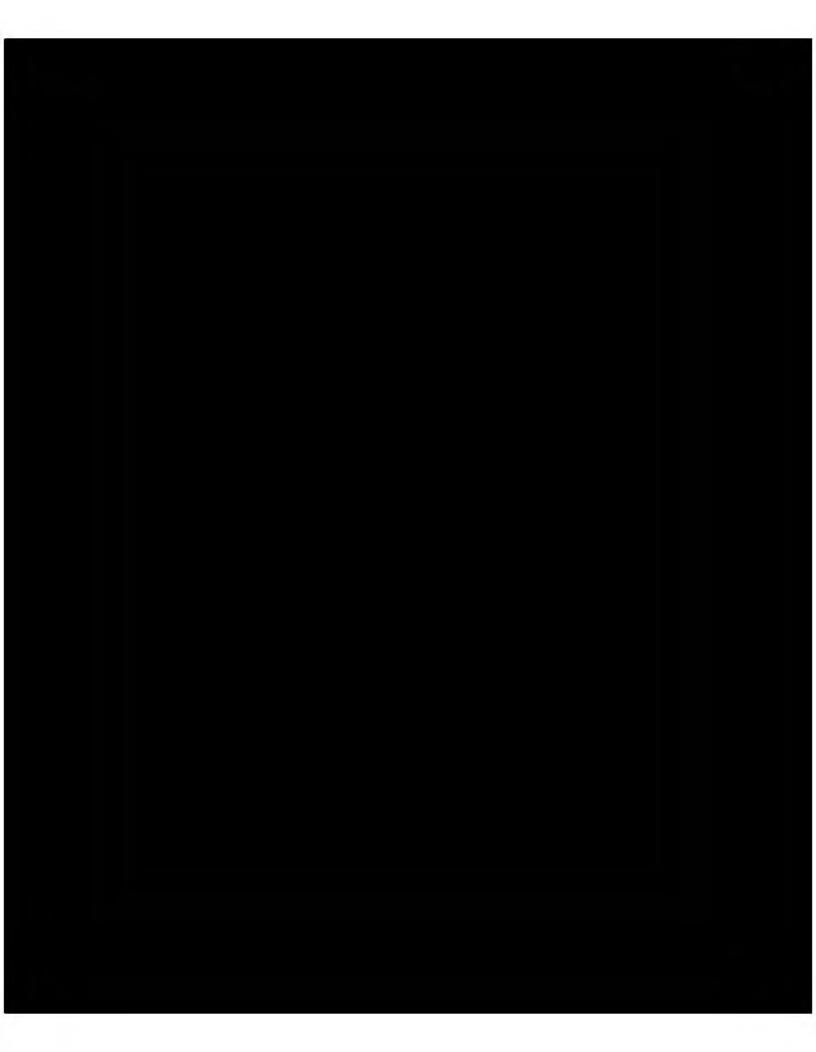


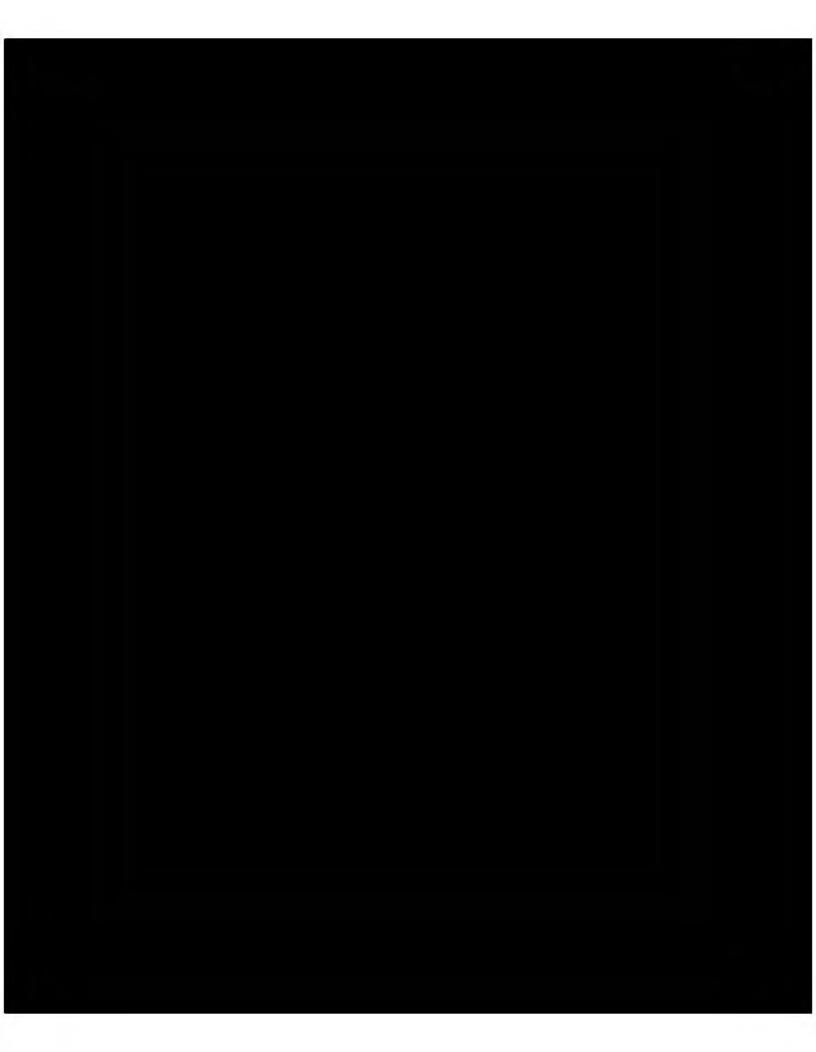


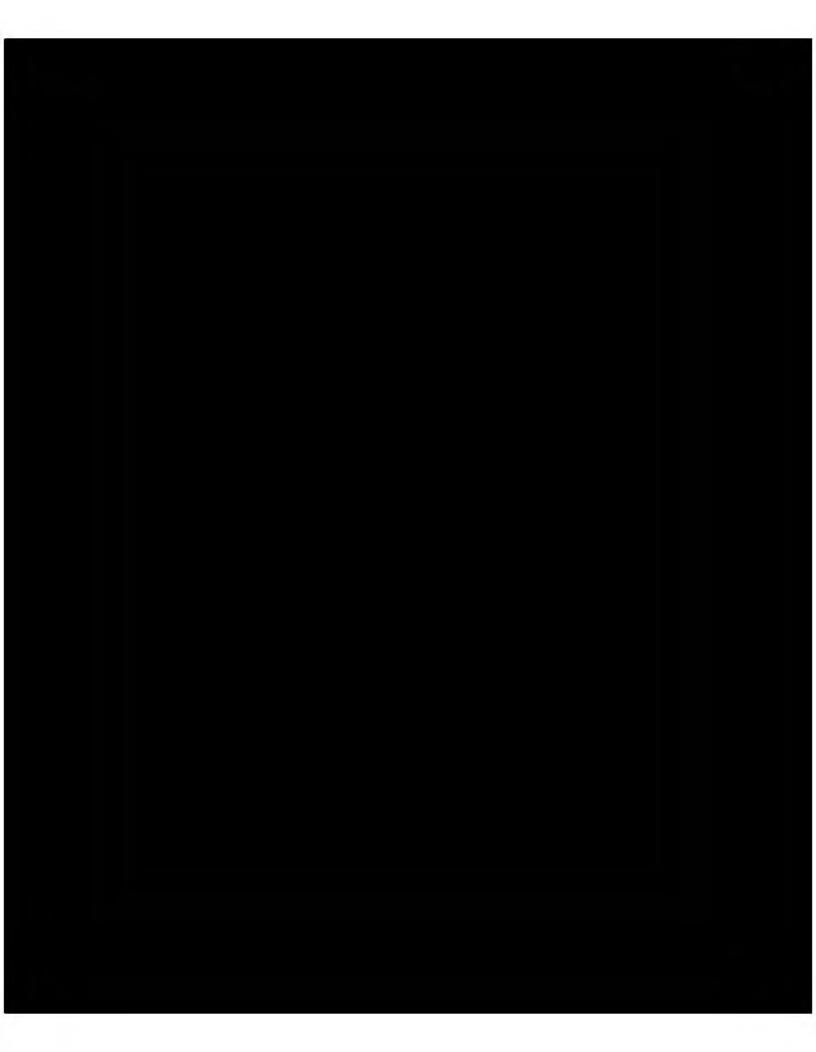


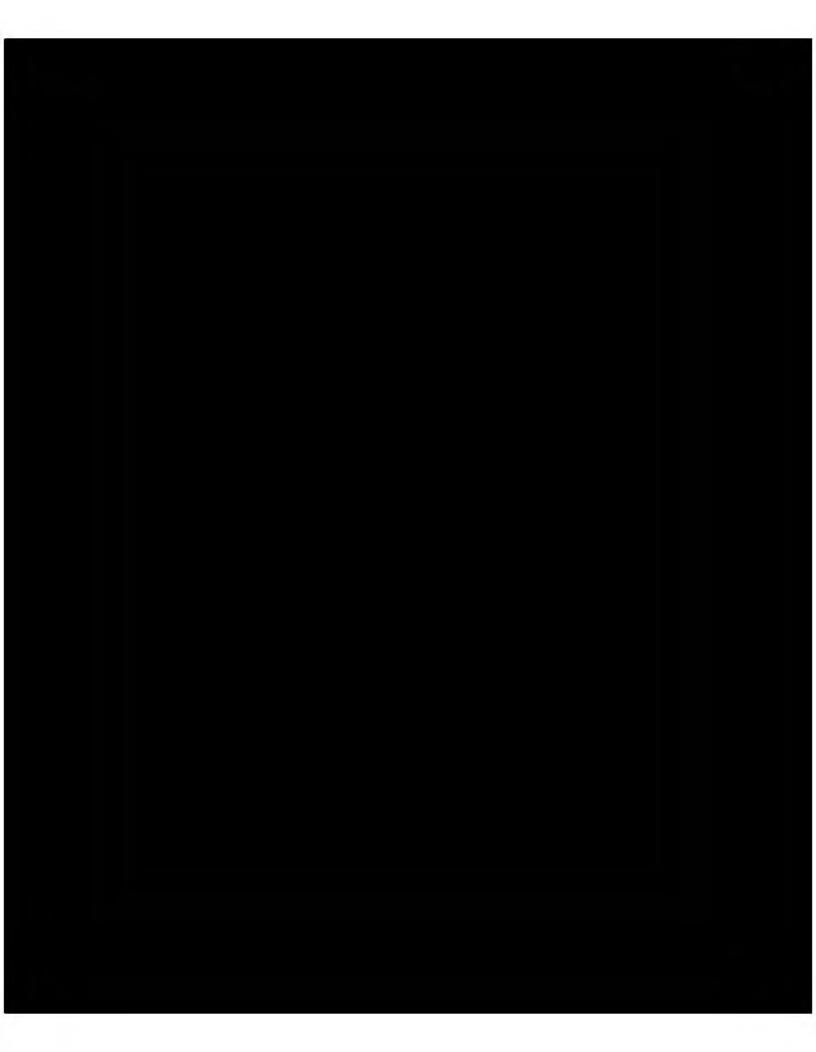


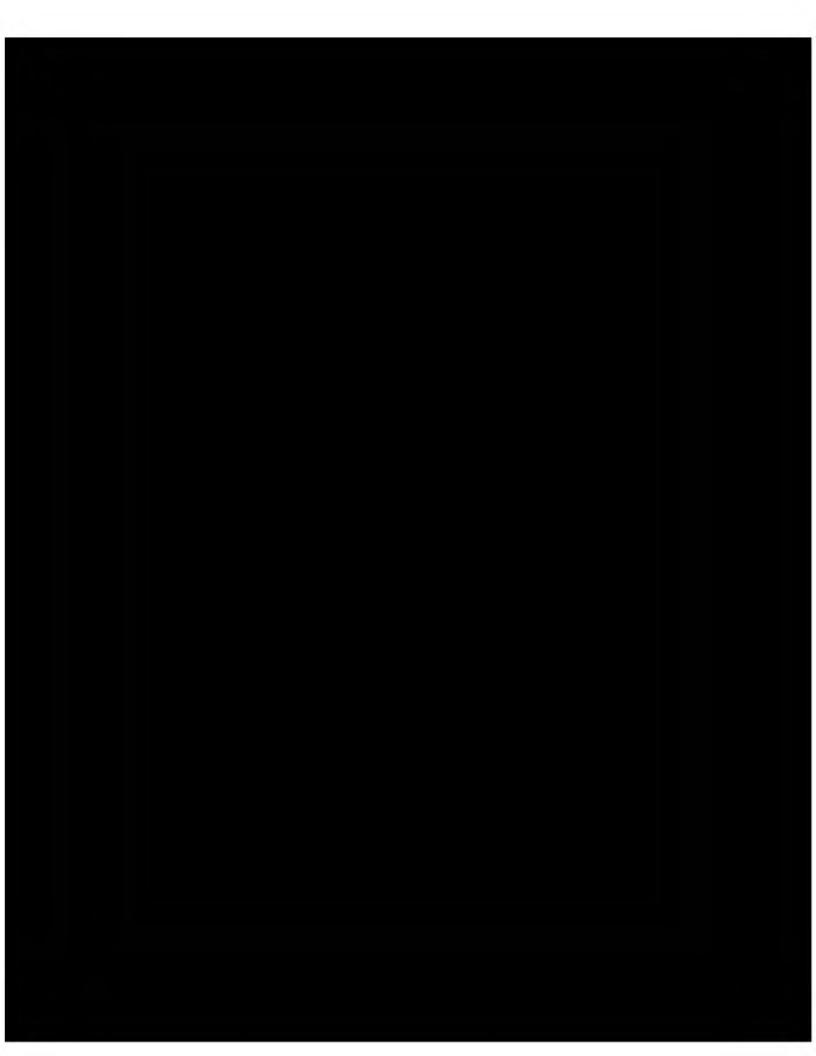




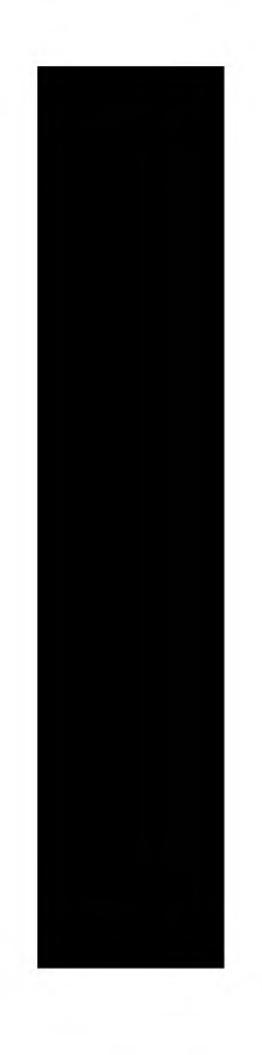








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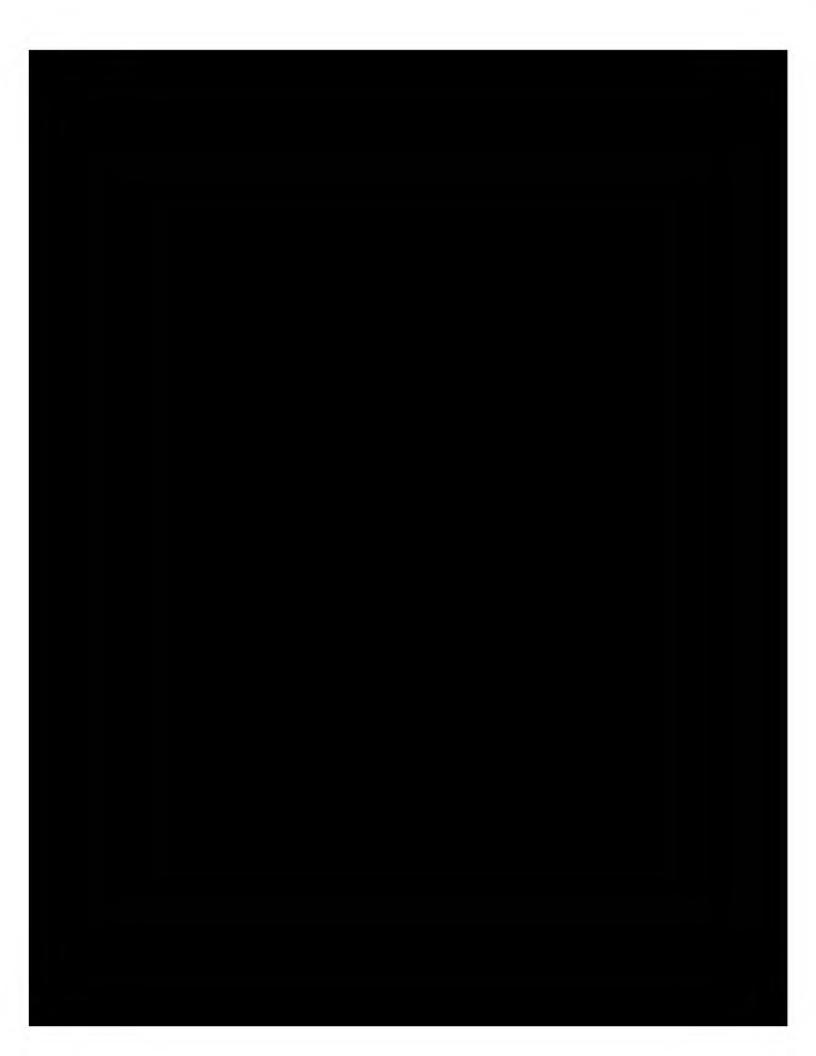
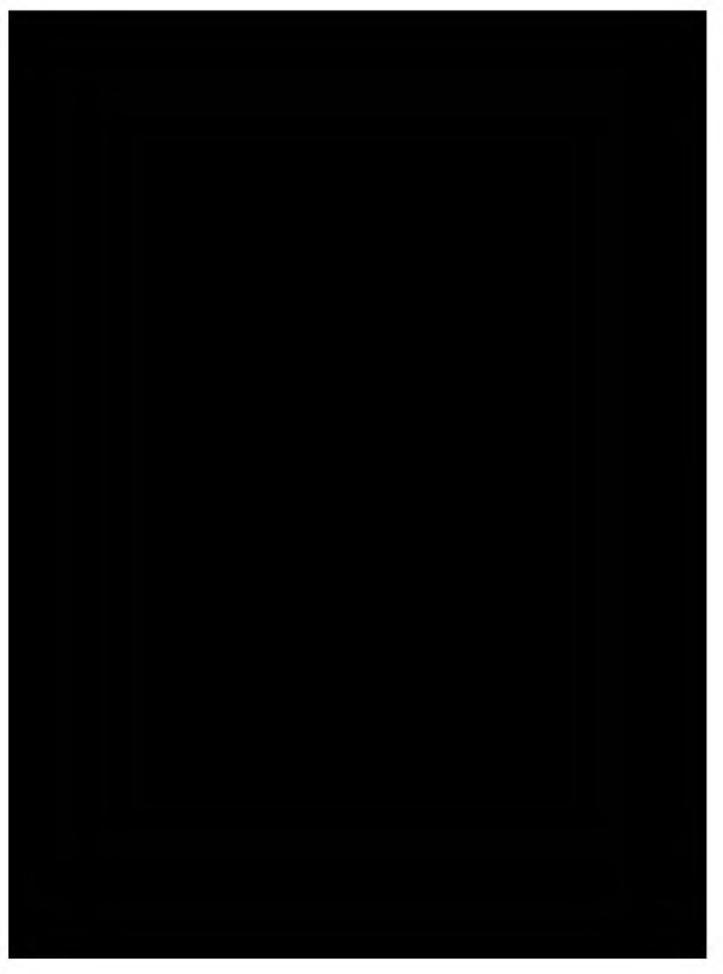
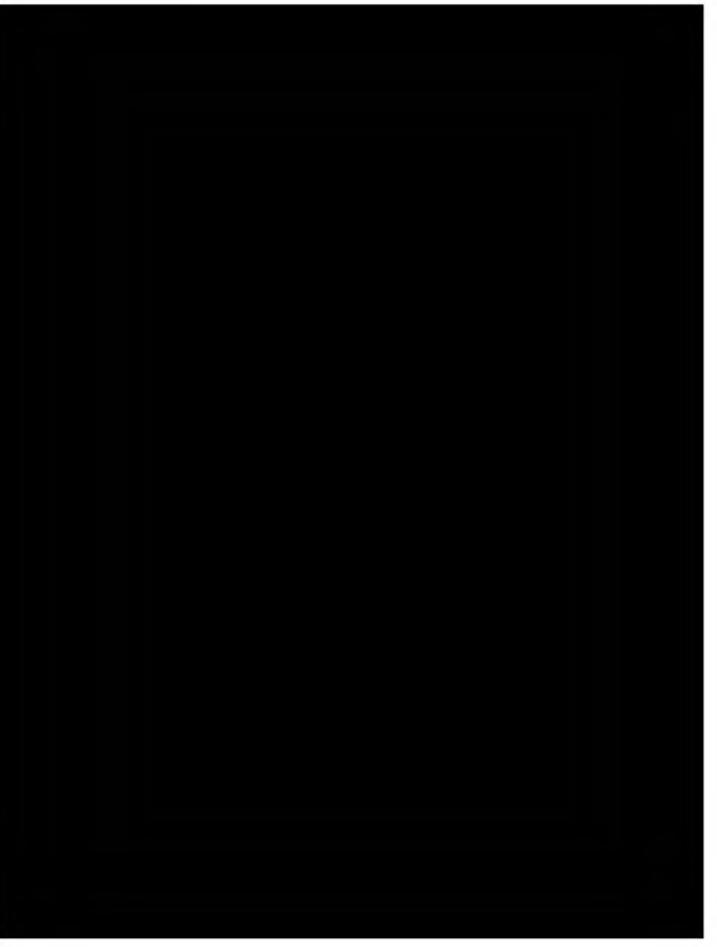




 Table 2.6-1.
 Data from USGS earthquake catalog for faults in the region of CTV III.







# APPENDIX: OPERATIONAL PROCEDURES 40 CFR 146.82(a)(10)

## CTV III

# **Operational Procedures**

Injectors will be operated to inject the desired target rate of  $CO_2$  over the specified operating period. Operating procedures for the 6 planned injectors in the project are described below.

# 1. Injector C1 Operating Procedures

For a target rate of MMSCFPD, bottom hole and surface pressures have been estimated for the well over the life of the project. These pressures were estimated using results from the Plume simulation as an input into the multiphase well nodal analysis software – PROSPER by Petroleum Experts Ltd. PROSPER has been used extensively in CO2 EOR to model CO2 injection wells. The pressures have been currently calculated assuming a 100% CO2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

At the start of injection, a surface and bottom hole injection pressure of 1240 psi and 2934 psi respectively, are required to inject. As the pressure in the reservoir builds up, higher surface and bottom hole pressures will be required. At the end of injection, the estimated surface and bottom hole pressures required are 1300 psi and 3050 psi respectively, which is the maximum pressure CTV expects to operate the well under target rate conditions.

The expected fracture pressure gradient for the injection zone is estimated to be 0.76psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable BHP is 4224 psi (calculated at the top perforation). The injection well will be controlled using automation so as to never cross this maximum BHP.

The expected pressures for injector C1 over the life of the project are summarized in Table 1.

Parameters/Conditions Limit or Permitted Value Unit Using 0.76psi/ft frac gradient with 10% Maximum Allowable Pressure safety factor Surface 2243 Psig Downhole 4224 Psig Injection Pressure @ Target rate Expected range over project Surface - Start / End | 1240 / 1300 Psig Downhole - Start / End | 2934 / 3050 Psig Mmscfpd Target Injection Rate Tonnes/day Annulus Pressure Expected range over project Surface - Start / End | 100 / 525 Psig Downhole - Start / End 2725 / 3150 Psig Annulus / Injection Tubing Pressure Differential >100 Psig

Table 1. Proposed operational procedures for Injector C1.

## 1.1 Annulus Pressure

Annular pressure between the tubing and production casing above the packer will be maintained to achieve the requirements of 40 CFR 146.88 (c).

The minimum applied annular surface pressure will be maintained at or greater than 100 psi during injection. This ensures a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to Attachment C: Testing and Monitoring Plan.

CTV will maintain downhole annular pressure at the packer greater than 100 psi above injection pressure for all bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure, as needed.

CTV intends to use 4% KCl completion fluid with corrosion inhibition and biocide as packer fluid. 4% KCl is compatible with all well components and is not corrosive. The specific gravity of the packer fluid is estimated to be 1.024.

The range of annular pressures described in Table 8 are suitable to the well design and will not impact the well integrity or induce formation fracture.

## 1.2 Maximum Injection Rate

Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the maximum injection rate.

At this time, for injection well C1, CTV expects a target injection rate of million cubic feet per day for which the maximum expected bottom hole injection pressure is 3050 psi. A threshold of 10% over these values will be used to configure automation and alarms, which equates to million cubic feet per day and 3355 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue. Resolution will depend on the type of alarm and systems installed to regulate the injection rate. Typically, this will require a reduction in the injection rate without the need for a shutdown. But the situation will be reviewed to understand what systems failed or did not perform properly and thus created an excessive injection rate.

#### 1.3 Shutdown Procedures

Under routine shutdowns (e.g., for well workovers), CTV will reduce CO2 injection at a rate of tons per day over a 6-day period to ensure protection of health, safety, and the environment.

#### 1.4 Automated Shutdown System

Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real time. Data will be collected in an automated system and monitored by a control system with established operating thresholds. After a threshold is seen or exceeded, the software will issue visual, audible, and digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate

equipment until it is understood why the thresholds were achieved and what corrective measures must be implemented.								
CTV has not established the monitoring system at this time. Upon establishing the system and thresholds CTV will communicate with the EPA.								

# 2. Injector C2 Operating procedures

For a target rate of MMSCFPD, bottom hole and surface pressures have been estimated for the well over the life of the project. These pressures were estimated using results from the Plume simulation as an input into the multiphase well nodal analysis software – PROSPER by Petroleum Experts Ltd. PROSPER has been used extensively in CO<sub>2</sub> EOR to model CO<sub>2</sub> injection wells. The pressures have been currently calculated assuming a 100% CO2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

At the start of injection, a surface and bottom hole injection pressure of 1390 psi and 3467 psi respectively, are required to inject. As the pressure in the reservoir builds up, higher surface and bottom hole pressures will be required. At the end of injection, the estimated surface and bottom hole pressures required are 1450 psi and 3566 psi respectively, which is the maximum pressure CTV expects to operate the well under target rate conditions.

The expected fracture pressure gradient for the injection zone is estimated to be 0.76psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable BHP is 4919 psi (calculated at the top perforation). The injection well will be controlled using automation so as to never cross this maximum BHP.

The expected pressures for injector C2 over the life of the project are summarized in Table 2.

Table 2. Proposed operational procedures for Injector C2.

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Allowable Pressure	Using 0.76psi/ft frac gradient with 10% safety factor	
Surface	2539	Psig
Downhole	4919	Psig
Injection Pressure @ Target rate	Expected range over project	
Surface - Start / End	1390 / 1450	Psig
Downhole - Start / End	3467 / 3566	Psig
Target Injection Rate		Mmscfpd
		Tonnes/day
Annulus Pressure	Expected range over project	5.
Surface - Start / End	100 / 1041	Psig
Downhole - Start / End	2725 / 3666	Psig
Annulus / Injection Tubing Pressure Differential	>100	Psig

## 2.1 Annulus Pressure

Annular pressure between the tubing and production casing above the packer will be maintained to achieve the requirements of 40 CFR 146.88 (c).

The minimum applied annular surface pressure will be maintained at or greater than 100 psi during injection. This ensures a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to Attachment C: Testing and Monitoring Plan.

CTV will maintain downhole annular pressure at the packer greater than 100 psi above injection pressure for all bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure, as needed.

CTV intends to use 4% KCl completion fluid with corrosion inhibition and biocide as packer fluid. 4% KCl is compatible with all well components and is not corrosive. The specific gravity of the packer fluid is estimated to be 1.024.

The range of annular pressures described in Table 8 are suitable to the well design and will not impact the well integrity or induce formation fracture.

#### 2.2 Maximum Injection Rate

Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the maximum injection rate.

At this time, for injection well C1, CTV expects a target injection rate of million cubic feet per day for which the maximum expected bottom hole injection pressure is 3566 psi. A threshold of 10% over these values will be used to configure automation and alarms, which equates to million cubic feet per day and 3923 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue. Resolution will depend on the type of alarm and systems installed to regulate the injection rate. Typically, this will require a reduction in the injection rate without the need for a shutdown. But the situation will be reviewed to understand what systems failed or did not perform properly and thus created an excessive injection rate.

#### 2.3 Shutdown Procedures

Under routine shutdowns (e.g., for well workovers), CTV will reduce CO2 injection at a rate of tons per day over a 6-day period to ensure protection of health, safety, and the environment.

#### 2.4 Automated Shutdown System

Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real time. Data will be collected in an automated system and monitored by a control system with established operating thresholds. After a threshold is seen or exceeded, the software will issue visual, audible, and digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate equipment until it is understood why the thresholds were achieved and what corrective measures must be implemented.

CTV has not established the monitoring system at this time. Upon establishing the system and thresholds CTV will communicate with the EPA.

# 3. Injector E1 Operating procedures

For a target rate of MMSCFPD, bottom hole and surface pressures have been estimated for the well over the life of the injection period. These pressures were estimated using results from the Plume simulation as an input into the multiphase well nodal analysis software – PROSPER by Petroleum Experts Ltd. PROSPER has been used extensively in CO<sub>2</sub> EOR to model CO<sub>2</sub> injection wells. The pressures have been currently calculated assuming a 100% CO2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

At the start of injection, a surface and bottom hole injection pressure of 1060 psi and 2760 psi respectively, are required. As the pressure in the reservoir builds up, higher surface and bottom hole pressures will be required. At the end of injection, the estimated surface and bottom hole pressures required are 1110 psi and 2901 psi respectively, which is the maximum pressure CTV expects to operate the well under target rate conditions.

The expected fracture pressure gradient for the injection zone is estimated to be 0.76psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable BHP is 4111 psi (calculated at the top perforation). The injection well will be controlled using automation so as to never cross this maximum BHP.

The expected pressures for injector E1 over the life of the project are summarized in Table 3.

Table 3. Proposed operational procedures for Injector E1.

Parameters/Conditions	Limit or Permitted Value	Unit
Maximum Allowable Pressure	Using 0.76psi/ft frac gradient with 10% safety factor	
Surface	2300	Psig
Downhole	4111	Psig
Injection Pressure @ Target rate	Expected range over project	
Surface - Start / End	1060 / 1110	Psig
Downhole - Start / End	2760 / 2901	Psig
Target Injection Rate		Mmscfpd
		Tonnes/day
Annulus Pressure	Expected range over project	3
Surface - Start / End	100 / 447	Psig
Downhole - Start / End	2654 / 3001	Psig
Annulus / Injection Tubing Pressure Differential	>100	Psig

## 3.1 Annulus Pressure

Annular pressure between the tubing and production casing above the packer will be maintained to achieve the requirements of 40 CFR 146.88 (c).

The minimum applied annular surface pressure will be maintained at or greater than 100 psi during injection. This ensures a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to Attachment C: Testing and Monitoring Plan.

CTV will maintain downhole annular pressure at the packer greater than 100 psi above injection pressure for all bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure, as needed.

CTV intends to use 4% KCl completion fluid with corrosion inhibition and biocide as packer fluid. 4% KCl is compatible with all well components and is not corrosive. The specific gravity of the packer fluid is estimated to be 1.024.

The range of annular pressures described in Table 8 are suitable to the well design and will not impact the well integrity or induce formation fracture.

#### 3.2 Maximum Injection Rate

Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the maximum injection rate.

At this time, for injection well C1, CTV expects a target injection rate of million cubic feet per day for which the maximum expected bottom hole injection pressure is 2901 psi. A threshold of 10% over these values will be used to configure automation and alarms, which equates to million cubic feet per day and 3191 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue. Resolution will depend on the type of alarm and systems installed to regulate the injection rate. Typically, this will require a reduction in the injection rate without the need for a shutdown. But the situation will be reviewed to understand what systems failed or did not perform properly and thus created an excessive injection rate.

#### 3.3 Shutdown Procedures

Under routine shutdowns (e.g., for well workovers), CTV will reduce CO2 injection at a rate of tons per day over a 6-day period to ensure protection of health, safety, and the environment.

## 3.4 Automated Shutdown System

Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real time. Data will be collected in an automated system and monitored by a control system with established operating thresholds. After a threshold is seen or exceeded, the software will issue visual, audible, and digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate equipment until it is understood why the thresholds were achieved and what corrective measures must be implemented.

CTV has not established the monitoring system at this time. Upon establishing the system and thresholds CTV will communicate with the EPA.

# 4. Injector E2 Operating procedures

For a target rate of MMSCFPD, bottom hole and surface pressures have been estimated for the well over the life of the injection period. These pressures were estimated using results from the Plume simulation as an input into the multiphase well nodal analysis software – PROSPER by Petroleum Experts Ltd. PROSPER has been used extensively in CO<sub>2</sub> EOR to model CO<sub>2</sub> injection wells. The pressures have been currently calculated assuming a 100% CO2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

At the start of injection, a surface and bottom hole injection pressure of 1140 psi and 3210 psi respectively, are required. As the pressure in the reservoir builds up, higher surface and bottom hole pressures will be required. At the end of injection, the estimated surface and bottom hole pressures required are 1180 psi and 3363 psi respectively, which is the maximum pressure CTV expects to operate the well under target rate conditions.

The expected fracture pressure gradient for the injection zone is estimated to be 0.76psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable BHP is 4774 psi (calculated at the top perforation). The injection well will be controlled using automation so as to never cross this maximum BHP.

The expected pressures for injector E2 over the life of the project are summarized in Table 4.

**Parameters/Conditions** Limit or Permitted Value Unit Using 0.76psi/ft frac gradient with 10% Maximum Allowable Pressure safety factor Surface 2254 Psig Downhole 4774 Psig Injection Pressure @ Target rate Expected range over project Surface - Start / End | 1140 / 1180 Psig Downhole - Start / End | 3210 / 3363 Psig Mmscfpd Target Injection Rate Tonnes/day Annulus Pressure Expected range over project Surface - Start / End | 100 / 909 Psig Downhole - Start / End 2654 / 3463 Psig Annulus / Injection Tubing Pressure Differential >100 Psig

Table 4. Proposed operational procedures for Injector E2.

#### 4.1 Annulus Pressure

Annular pressure between the tubing and production casing above the packer will be maintained to achieve the requirements of 40 CFR 146.88 (c).

The minimum applied annular surface pressure will be maintained at or greater than 100 psi during injection. This ensures a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to Attachment C: Testing and Monitoring Plan.

CTV will maintain downhole annular pressure at the packer greater than 100 psi above injection pressure for all bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure, as needed.

CTV intends to use 4% KCl completion fluid with corrosion inhibition and biocide as packer fluid. 4% KCl is compatible with all well components and is not corrosive. The specific gravity of the packer fluid is estimated to be 1.024.

The range of annular pressures described in Table 8 are suitable to the well design and will not impact the well integrity or induce formation fracture.

## 4.2 Maximum Injection Rate

Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the maximum injection rate.

At this time, for injection well C1, CTV expects a target injection rate of million cubic feet per day for which the maximum expected bottom hole injection pressure is 3363 psi. A threshold of 10% over these values will be used to configure automation and alarms, which equates to million cubic feet per day and 3699 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue. Resolution will depend on the type of alarm and systems installed to regulate the injection rate. Typically, this will require a reduction in the injection rate without the need for a shutdown. But the situation will be reviewed to understand what systems failed or did not perform properly and thus created an excessive injection rate.

#### 4.3 Shutdown Procedures

Under routine shutdowns (e.g., for well workovers), CTV will reduce CO2 injection at a rate of tons per day over a 6-day period to ensure protection of health, safety, and the environment.

#### 4.4 Automated Shutdown System

Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real time. Data will be collected in an automated system and monitored by a control system with established operating thresholds. After a threshold is seen or exceeded, the software will issue visual, audible, and digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate

equipment until it is understood why the thresholds were achieved and what corrective measures must be implemented.								
CTV has not established the monitoring system at this time. Upon establishing the system and thresholds CTV will communicate with the EPA.								

# 5. Injector W1 Operating procedures

For a target rate of MMSCFPD, bottom hole and surface pressures have been estimated for the well over the life of the injection period. These pressures were estimated using results from the Plume simulation as an input into the multiphase well nodal analysis software – PROSPER by Petroleum Experts Ltd. PROSPER has been used extensively in CO<sub>2</sub> EOR to model CO<sub>2</sub> injection wells. The pressures have been currently calculated assuming a 100% CO2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

At the start of injection, a surface and bottom hole injection pressure of 1080 psi and 2856 psi respectively, are required. As the pressure in the reservoir builds up, higher surface and bottom hole pressures will be required. At the end of injection, the estimated surface and bottom hole pressures required are 1120 psi and 2961 psi respectively, which is the maximum pressure CTV expects to operate the well under target rate conditions.

The expected fracture pressure gradient for the injection zone is estimated to be 0.76psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable BHP is 4207 psi (calculated at the top perforation). The injection well will be controlled using automation so as to never cross this maximum BHP.

The expected pressures for injector W1 over the life of the project are summarized in Table 5.

Parameters/Conditions Limit or Permitted Value Unit Using 0.76psi/ft frac gradient with 10% Maximum Allowable Pressure safety factor Surface 2036 Psig Downhole 4207 Psig Injection Pressure @ Target rate Expected range over project Surface - Start / End | 1080 / 1120 Psig Downhole - Start / End 2856 / 2961 Psig Mmscfpd Target Injection Rate Tonnes/day Annulus Pressure Expected range over project Surface - Start / End | 100 / 361 Psig Downhole - Start / End | 2800 / 3061 Psig Annulus / Injection Tubing Pressure Differential >100 Psig

Table 5. Proposed operational procedures for Injector W1.

### 5.1 Annulus Pressure

Annular pressure between the tubing and production casing above the packer will be maintained to achieve the requirements of 40 CFR 146.88 (c).

The minimum applied annular surface pressure will be maintained at or greater than 100 psi during injection. This ensures a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to Attachment C: Testing and Monitoring Plan.

CTV will maintain downhole annular pressure at the packer greater than 100 psi above injection pressure for all bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure, as needed.

CTV intends to use 4% KCl completion fluid with corrosion inhibition and biocide as packer fluid. 4% KCl is compatible with all well components and is not corrosive. The specific gravity of the packer fluid is estimated to be 1.024.

The range of annular pressures described in Table 8 are suitable to the well design and will not impact the well integrity or induce formation fracture.

#### 5.2 Maximum Injection Rate

Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the maximum injection rate.

At this time, for injection well C1, CTV expects a target injection rate of million cubic feet per day for which the maximum expected bottom hole injection pressure is 2961 psi. A threshold of 10% over these values will be used to configure automation and alarms, which equates to million cubic feet per day and 3257 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue. Resolution will depend on the type of alarm and systems installed to regulate the injection rate. Typically, this will require a reduction in the injection rate without the need for a shutdown. But the situation will be reviewed to understand what systems failed or did not perform properly and thus created an excessive injection rate.

## 5.3 Shutdown Procedures

Under routine shutdowns (e.g., for well workovers), CTV will reduce CO2 injection at a rate of tons per day over a 6-day period to ensure protection of health, safety, and the environment.

#### 5.4 Automated Shutdown System

Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real time. Data will be collected in an automated system and monitored by a control system with established operating thresholds. After a threshold is seen or exceeded, the software will issue visual, audible, and digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate

equipment until it is understood why the thresholds were achieved and what corrective measures must be implemented. $ \\$				
CTV has not established the monitoring system at this time. Upon establishing the system and thresholds CTV will communicate with the EPA.				

# 6. Injector W2 Operating procedures

For a target rate of MMSCFPD, bottom hole and surface pressures have been estimated for the well over the life of the injection period. These pressures were estimated using results from the Plume simulation as an input into the multiphase well nodal analysis software – PROSPER by Petroleum Experts Ltd. PROSPER has been used extensively in CO<sub>2</sub> EOR to model CO<sub>2</sub> injection wells. The pressures have been currently calculated assuming a 100% CO2 stream. Operating conditions will be updated as CTV defines the injection stream and impurities.

At the start of injection, a surface and bottom hole injection pressure of 1170 psi and 3370 psi respectively, are required. As the pressure in the reservoir builds up, higher surface and bottom hole pressures will be required. At the end of injection, the estimated surface and bottom hole pressures required are 1240 psi and 3504 psi respectively, which is the maximum pressure CTV expects to operate the well under target rate conditions.

The expected fracture pressure gradient for the injection zone is estimated to be 0.76psi/ft. Using a 10% safety factor, as per the EPA's guidelines, the maximum allowable BHP is 4802 psi (calculated at the top perforation). The injection well will be controlled using automation so as to never cross this maximum BHP.

The expected pressures for injector W2 over the life of the project are summarized in Table 6.

Parameters/Conditions Limit or Permitted Value Unit Using 0.76psi/ft frac gradient with 10% Maximum Allowable Pressure safety factor Surface 2272 Psig Downhole 4802 Psig Injection Pressure @ Target rate Expected range over project Surface - Start / End | 1170 / 1240 psig Downhole - Start / End | 3370 / 3504 psig mmscfpd Target Injection Rate Tonnes/day Annulus Pressure Expected range over project Surface - Start / End | 100 / 913 psig Downhole - Start / End | 2791 / 3604 psig Annulus / Injection Tubing Pressure Differential >100 psig

Table 6. Proposed operational procedures for Injector W2.

### **6.1 Annulus Pressure**

Annular pressure between the tubing and production casing above the packer will be maintained to achieve the requirements of 40 CFR 146.88 (c).

The minimum applied annular surface pressure will be maintained at or greater than 100 psi during injection. This ensures a low-pressure alarm can be used to indicate loss of annular pressure as a potential well integrity concern. Surface pressure will be monitored continuously and evaluated according to Attachment C: Testing and Monitoring Plan.

CTV will maintain downhole annular pressure at the packer greater than 100 psi above injection pressure for all bottomhole injection pressures. This pressure differential is achieved by the combination of hydrostatic pressure from annular packer fluid and surface applied annular pressure, as needed.

CTV intends to use 4% KCl completion fluid with corrosion inhibition and biocide as packer fluid. 4% KCl is compatible with all well components and is not corrosive. The specific gravity of the packer fluid is estimated to be 1.024.

The range of annular pressures described in Table 8 are suitable to the well design and will not impact the well integrity or induce formation fracture.

### 6.2 Maximum Injection Rate

Surface wellhead and downhole conditions will be monitored continuously. Injection rate or mass flow is one of the parameters to be monitored at surface. Thresholds will be established based on limitations of well equipment and geological concerns downhole with respect to the maximum injection rate.

At this time, for injection well C1, CTV expects a target injection rate of million cubic feet per day for which the maximum expected bottom hole injection pressure is 3504 psi. A threshold of 10% over these values will be used to configure automation and alarms, which equates to million cubic feet per day and 3854 psi. If either threshold is achieved or exceeded, the system will deliver alarms to indicate there is an issue. Resolution will depend on the type of alarm and systems installed to regulate the injection rate. Typically, this will require a reduction in the injection rate without the need for a shutdown. But the situation will be reviewed to understand what systems failed or did not perform properly and thus created an excessive injection rate.

#### 6.3 Shutdown Procedures

Under routine shutdowns (e.g., for well workovers), CTV will reduce CO2 injection at a rate of tons per day over a 6-day period to ensure protection of health, safety, and the environment.

#### 6.4 Automated Shutdown System

Downhole temperature and pressure along with surface flow or mass movement, surface pressure, and temperatures will be monitored in real time. Data will be collected in an automated system and monitored by a control system with established operating thresholds. After a threshold is seen or exceeded, the software will issue visual, audible, and digital alerts and/or begin with an unload procedure and transition into the shutdown process for appropriate

equipment until it is understood why the thresholds were achieved and what corrective measures must be implemented.
CTV has not established the monitoring system at this time. Upon establishing the system and thresholds CTV will communicate with the EPA.

## APPLICABLE FEDERAL LAWS CTV III

#### Wild and Scenic Rivers Act (WSR Act)

The Wild and Scenic Rivers Act (WSR Act) of 1968 (Public Law 90-542; 16 U.S.C. 1271 *et seq.*) was enacted by Congress to preserve certain rivers with outstanding natural, cultural, and recreational values in a free-flowing condition for the enjoyment of present and future generations. The WSR Act is notable for safeguarding the special character of these rivers, while also recognizing the potential for their appropriate use and development. It encourages river management that crosses political boundaries and promotes public participation in developing goals for river protection.

The National Wild and Scenic Rivers System (NWSRS) was created by the WSR Act and is managed by the National Park Service and the U.S. Forest Service. Rivers may be designated by Congress, or if certain requirements are met, they may be designated by the Secretary of the Interior. Designated segments need not include the entire river and may include tributaries. Each river is administered by either a federal or state agency. Section 2(b) of the WSR Act creates three classifications of protected rivers, which are defined as follows:

- "Wild River Areas" are those rivers or sections of rivers that are free of impoundments and generally inaccessible except by trail, with watersheds or shorelines essentially primitive and waters unpolluted. These represent vestiges of America.
- "Scenic River Areas" are those rivers or sections of rivers that are free of impoundments, with shorelines or watersheds still largely primitive and shorelines largely undeveloped, but accessible in places by roads.
- "Recreational River Areas" are those rivers or sections of rivers that are readily accessible by road or railroad, that may have some development along their shorelines, and that may have undergone some impoundment or diversion in the past.

Regardless of the classification, each river in the National System is administered with the goal of protecting and enhancing the values for which it was designated.



# National Historic Preservation Act (NHPA) – National Historic Preservation Act (NHPA) §106

First passed in 1966, the National Historic Preservation Act (NHPA; Public Law 89-665; 54 U.S.C. 300101 et seq.) is legislation intended to preserve historic and archaeological sites in the United States of America. The act created the National Register of Historic Places, the list of National Historic Landmarks, and the State Historic Preservation Offices.

Section 106 of the National Historic Preservation Act mandates federal agencies undergo a review process for all federally funded and permitted projects that will impact sites listed on, or eligible for

listing on, the National Register of Historic Places. Specifically, it requires the federal agency to "take into account" the effect a project may have on historic properties. It allows interested parties an opportunity to comment on the potential impact projects may have on significant archaeological or historic sites. The main purpose for the establishment of the Section 106 review process is to minimize potential harm and damage to historic properties.

CRC has retained a qualified archaeologist to conduct an archival records search, as well as pedestrian surveys, and to initiate Native American tribal consultation as necessary. Prior to the proposed project undertaking, the archival records search will be conducted to determine: (i) if prehistoric or historical archaeological sites has previously been recorded within the project study area; (ii) if the project area has been systematically surveyed by archaeologists prior to the initiation of this field study; and/or (iii) whether the region of the project is known to contain archaeological sites and to thereby be archaeologically sensitive. Additionally, a record search of the Native American Heritage Commission (NAHC) *Sacred Lands File* will be conducted to ascertain whether traditional cultural places or cultural landscapes had been identified within the proposed project site. Any historic findings will be evaluated to determine significance and a plan to avoid and mitigate any adverse impacts to archaeological resources will be prepared by the qualified archaeologist for the Project as applicable.

#### Endangered Species Act (ESA) – (16 U.S.C. 1531 et seq.)

Enacted in 1973, the ESA is administered by the USFWS and the National Oceanic and Atmospheric Administration Fisheries Service (formerly National Marine Fisheries Service). The purpose of the ESA is to conserve and recover endangered and threatened species, as well as the ecosystems upon which they depend. ESA requires all federal agencies to protect listed species and preserve their habitats. Section 4 of ESA sets forth a process for listing species as endangered or threatened, for designating critical habitat for listed species, and for preparing recovery plans for listed species. Section 7 requires federal agencies to consult with the USFWS or National Oceanic and Atmospheric Administration Fisheries Service to ensure their actions do not jeopardize listed species. Section 9 prohibits the "take" of a listed species. Section 10 provides a means whereby a nonfederal action with the potential to result in the incidental take of a listed species while carrying out an otherwise lawful activity may be authorized under a permit. Section 11 sets forth enforcement and penalty provisions. Under the ESA, "take" of listed wildlife species is prohibited, unless take authorization is first obtained from the USFWS. "Take" is broadly defined under the ESA and means to harass, harm, hunt, shoot, wound, kill, trap, capture, or collect, or attempt to engage in any such conduct.

Based on initial review of the IPaC, the proposed project footprint overlaps designated critical habitat for Contra Costa Goldfields (*Lasthenia conjugens*), Delta Smelt (*Hypomesus transpacificus*), and Vernal Pool Fairy Shrimp (*Branchinecta lynchi*). A total of 15 federally listed species may be present and/or adversely impacted by the proposed project. A species list obtained from the USFWS IPaC for listed species and critical habitats that may be present in or adversely affected by the proposed project is attached as reference (Figure ENV-1).

As the project planning progresses, CRC will obtain an official species list from the USFWS and resume review of the project's effects on listed species pursuant to the ESA as part of the overall regulatory review. Potential impacts on resources managed by the USFWS will be evaluated and applicable conservation measures will be designed to avoid or minimize effects to listed species, CRC has an existing contract with a qualified third-party environmental consultant to assist with biological preactivity surveys, biological assessment/report preparation, and biological and mitigation compliance monitoring as necessary.

## **Coastal Zone Management Act (CZMA)**

In 1972 Congress enacted the Coastal Zone Management Act (CZMA) (16 U.S.C. 1451 et seq.) to protect the coastal environment from growing demands associated with residential, recreational, commercial, and industrial uses (e.g., State and Federal offshore oil and gas development). The CZMA provisions help States develop coastal management programs (Programs) to manage and balance competing uses of the coastal zone. Federal Agencies must follow the Federal Consistency provisions as delineated in 15 CFR part 930.

The CZMA requires that Federal actions that are reasonably likely to affect any land or water use or natural resource of the coastal zone be consistent with enforceable policies of a State's federally approved coastal management program. The "effects test" is used to determine whether an activity is subject to Federal consistency provisions:

- Will the activity directly, indirectly, or cumulatively affect any natural resources, land uses, or water uses in the coastal zone?
  - o If yes, then the activity is subject to Federal consistency.
  - o If no, then the activity is not subject to Federal consistency

As per 16 U.S.C. § 1453. Definitions (1) The term "coastal zone" means the coastal waters (including the lands therein and thereunder) and the adjacent shorelands (including the waters therein and thereunder), strongly influenced by each other and in proximity to the shorelines of the several coastal states, and includes islands, transitional and intertidal areas, salt marshes, wetlands, and beaches. The zone extends inland from the shorelines only to the extent necessary to control shorelands, the uses of which have a direct and significant impact on the coastal waters, and to control those geographical areas which are likely to be affected by or vulnerable to sea level rise.

#### Fish and Wildlife Conservation Act (FWCA)

The Fish and Wildlife Conservation Act (FWCA) of 1980 (16 U.S.C. §§ 2901 et seq.) declares that fish and wildlife are of ecological, educational, esthetic, cultural, recreational, economic, and scientific value to the Nation. The Act acknowledges that historically, fish and wildlife conservation programs have focused on more recreationally and commercially important species within a particular ecosystem, without provisions for the conservation and management of nongame fish and wildlife. The purposes of this Act are to encourage all federal departments and agencies to utilize their statutory and administrative authority, to the maximum extent practicable and consistent with each agency's statutory responsibilities, and to conserve and to promote conservation of non-game fish and wildlife and their habitats. The FWCA defines "non-game fish and wildlife" as wild vertebrate animals in an unconfined state, that are not ordinarily taken for sport, fur, or food, not listed as endangered or threatened species, and not marine mammals within the context of the Marine Mammal Protection Act. Another purpose is to provide financial and technical assistance to the states for the development, revision, and implementation of conservation plans and programs for nongame fish and wildlife.

The proposed project area overlaps the plan area for the East Contra Costa County Natural Community Conservation Plan (NCCP)/Habitat Conservation Plan (HCP) and the proposed Bay/Delta Conservation Plan NCCP/HCP.

CRC will consult with the applicable City or County to determine if proposed project activities require coverage under the NCCP/HCP(s).				

# Figure ENV-1

# IPaC resource list

This report is an automatically generated list of species and other resources such as critical habitat (collectively referred to as *trust resources*) under the U.S. Fish and Wildlife Service's (USFWS) jurisdiction that are known or expected to be on or near the project area referenced below. The list may also include trust resources that occur outside of the project area, but that could potentially be directly or indirectly affected by activities in the project area. However, determining the likelihood and extent of effects a project may have on trust resources typically requires gathering additional site-specific (e.g., vegetation/species surveys) and project-specific (e.g., magnitude and timing of proposed activities) information.

Below is a summary of the project information you provided and contact information for the USFWS office(s) with jurisdiction in the defined project area. Please read the introduction to each section that follows (Endangered Species, Migratory Birds, USFWS Facilities, and NWI Wetlands) for additional information applicable to the trust resources addressed in that section.

# Location



# Local offices

San Francisco Bay-Delta Fish And Wildlife

**(**916) 930-5603

(916) 930-5654

650 Capitol Mall

Suite 8-300 Sacramento, CA 95814

http://kim\_squires@fws.gov

Sacramento Fish And Wildlife Office

**4** (916) 414-6600

**(916)** 414-6713

Federal Building



# Endangered species

This resource list is for informational purposes only and does not constitute an analysis of project level impacts.

The primary information used to generate this list is the known or expected range of each species. Additional areas of influence (AOI) for species are also considered. An AOI includes areas outside of the species range if the species could be indirectly affected by activities in that area (e.g., placing a dam upstream of a fish population even if that fish does not occur at the dam site, may indirectly impact the species by reducing or eliminating water flow downstream). Because species can move, and site conditions can change, the species on this list are not guaranteed to be found on or near the project area. To fully determine any potential effects to species, additional site-specific and project-specific information is often required.

Section 7 of the Endangered Species Act **requires** Federal agencies to "request of the Secretary information whether any species which is listed or proposed to be listed may be present in the area of such proposed action" for any project that is conducted, permitted, funded, or licensed by any Federal agency. A letter from the local office and a species list which fulfills this requirement can **only** be obtained by requesting an official species list from either the Regulatory Review section in IPaC (see directions below) or from the local field office directly.

For project evaluations that require USFWS concurrence/review, please return to the IPaC website and request an official species list by doing the following:

- 1. Draw the project location and click CONTINUE.
- 2. Click DEFINE PROJECT.
- 3. Log in (if directed to do so).
- 4. Provide a name and description for your project.
- 5. Click REQUEST SPECIES LIST.

Listed species<sup>1</sup> and their critical habitats are managed by the <u>Ecological Services Program</u> of the U.S. Fish and Wildlife Service (USFWS) and the fisheries division of the National Oceanic and Atmospheric Administration (NOAA Fisheries<sup>2</sup>).

Species and critical habitats under the sole responsibility of NOAA Fisheries are **not** shown on this list. Please contact <u>NOAA Fisheries</u> for <u>species under their jurisdiction</u>.

1. Species listed under the <u>Endangered Species Act</u> are threatened or endangered; IPaC also shows species that are candidates, or proposed, for listing. See the <u>listing status page</u> for more information. IPaC only shows species that are regulated by USFWS (see FAQ).

2. <u>NOAA Fisheries</u>, also known as the National Marine Fisheries Service (NMFS), is an office of the National Oceanic and Atmospheric Administration within the Department of Commerce.

The following species are potentially affected by activities in this location:

# **Mammals**

NAME STATUS

Riparian Brush Rabbit Sylvilagus bachmani riparius

Wherever found

No critical habitat has been designated for this species.

https://ecos.fws.gov/ecp/species/6189

Endangered

San Joaquin Kit Fox Vulpes macrotis mutica

Wherever found

No critical habitat has been designated for this species.

https://ecos.fws.gov/ecp/species/2873

Endangered

# Reptiles

NAME

Alameda Whipsnake (=striped Racer) Masticophis lateralis

euryxanthus

Wherever found

There is **final** critical habitat for this species. The location of the critical habitat is not available.

https://ecos.fws.gov/ecp/species/5524

Threatened

Giant Garter Snake Thamnophis gigas

Wherever found

No critical habitat has been designated for this species.

https://ecos.fws.gov/ecp/species/4482

Threatened

# **Amphibians**

NAME STATUS

California Red-legged Frog Rana draytonii

Wherever found

There is **final** critical habitat for this species. The location of the critical habitat is not available.

https://ecos.fws.gov/ecp/species/2891

Threatened

# California Tiger Salamander Ambystoma californiense

There is **final** critical habitat for this species. The location of the critical habitat is not available.

https://ecos.fws.gov/ecp/species/2076

## **Threatened**

# **Fishes**

NAME STATUS

Delta Smelt Hypomesus transpacificus

Wherever found

There is **final** critical habitat for this species. Your location overlaps the critical habitat.

https://ecos.fws.gov/ecp/species/321

Threatened

# Insects

NAME

Monarch Butterfly Danaus plexippus

Wherever found

No critical habitat has been designated for this species.

https://ecos.fws.gov/ecp/species/9743

Candidate

Valley Elderberry Longhorn Beetle Desmocerus californicus

dimorphus

Wherever found

There is **final** critical habitat for this species. The location of the critical habitat is not available.

https://ecos.fws.gov/ecp/species/7850

Threatened

# Crustaceans

NAME STATUS

Conservancy Fairy Shrimp Branchinecta conservatio

Wherever found

There is **final** critical habitat for this species. The location of the critical habitat is not available.

https://ecos.fws.gov/ecp/species/8246

**Endangered** 

# Longhorn Fairy Shrimp Branchinecta longiantenna

Wherever found

There is **final** critical habitat for this species. The location of the critical habitat is not available.

https://ecos.fws.gov/ecp/species/4294

# Vernal Pool Fairy Shrimp Branchinecta lynchi

Wherever found

There is **final** critical habitat for this species. Your location overlaps the critical habitat.

https://ecos.fws.gov/ecp/species/498

**Threatened** 

**Endangered** 

# Vernal Pool Tadpole Shrimp Lepidurus packardi

Wherever found

There is final critical habitat for this species. The location of the critical habitat is not available.

https://ecos.fws.gov/ecp/species/2246

**Endangered** 

# Flowering Plants

NAME **STATUS** 

Contra Costa Goldfields Lasthenia conjugens

Wherever found

There is final critical habitat for this species. Your location overlaps the critical habitat.

https://ecos.fws.gov/ecp/species/7058

**Endangered** 

# Large-flowered Fiddleneck Amsinckia grandiflora

Wherever found

There is final critical habitat for this species. The location of the critical habitat is not available.

https://ecos.fws.gov/ecp/species/5558

**Endangered** 

# Critical habitats

Potential effects to critical habitat(s) in this location must be analyzed along with the endangered species themselves.

This location overlaps the critical habitat for the following species:

NAME **TYPF** 

Contra Costa Goldfields Lasthenia conjugens

https://ecos.fws.gov/ecp/species/7058#crithab

Final

**Delta Smelt** Hypomesus transpacificus <a href="https://ecos.fws.gov/ecp/species/321#crithab">https://ecos.fws.gov/ecp/species/321#crithab</a>

Final

**Vernal Pool Fairy Shrimp** Branchinecta lynchi <a href="https://ecos.fws.gov/ecp/species/498#crithab">https://ecos.fws.gov/ecp/species/498#crithab</a>

Final

# Migratory birds

Certain birds are protected under the Migratory Bird Treaty Act<sup>1</sup> and the Bald and Golden Eagle Protection Act<sup>2</sup>.

Any person or organization who plans or conducts activities that may result in impacts to migratory birds, eagles, and their habitats should follow appropriate regulations and consider implementing appropriate conservation measures, as described <u>below</u>.

- 1. The Migratory Birds Treaty Act of 1918.
- 2. The Bald and Golden Eagle Protection Act of 1940.

Additional information can be found using the following links:

- Birds of Conservation Concern <a href="https://www.fws.gov/program/migratory-birds/species">https://www.fws.gov/program/migratory-birds/species</a>
- Measures for avoiding and minimizing impacts to birds
   <a href="https://www.fws.gov/library/collections/avoiding-and-minimizing-incidental-take-migratory-birds">https://www.fws.gov/library/collections/avoiding-and-minimizing-incidental-take-migratory-birds</a>
- Nationwide conservation measures for birds <a href="https://www.fws.gov/sites/default/files/documents/nationwide-standard-conservation-measures.pdf">https://www.fws.gov/sites/default/files/documents/nationwide-standard-conservation-measures.pdf</a>

The birds listed below are birds of particular concern either because they occur on the USFWS Birds of Conservation Concern (BCC) list or warrant special attention in your project location. To learn more about the levels of concern for birds on your list and how this list is generated, see the FAQ below. This is not a list of every bird you may find in this location, nor a guarantee that every bird on this list will be found in your project area. To see exact locations of where birders and the general public have sighted birds in and around your project area, visit the E-bird data mapping tool (Tip: enter your location, desired date range and a species on your list). For projects that occur off the Atlantic Coast, additional maps and models detailing the relative occurrence and abundance of bird species on your list are available. Links to additional information about Atlantic Coast birds, and other important information about your migratory bird list, including how to properly interpret and use your migratory bird report, can be found below.

For guidance on when to schedule activities or implement avoidance and minimization measures to reduce impacts to migratory birds on your list, click on the PROBABILITY OF PRESENCE SUMMARY at the top of your list to see when these birds are most likely to be present and breeding in your project area.

NAME

BREEDING SEASON (IF A
BREEDING SEASON IS
INDICATED FOR A BIRD ON
YOUR LIST, THE BIRD MAY
BREED IN YOUR PROJECT AREA
SOMETIME WITHIN THE
TIMEFRAME SPECIFIED, WHICH
IS A VERY LIBERAL ESTIMATE
OF THE DATES INSIDE WHICH
THE BIRD BREEDS ACROSS ITS
ENTIRE RANGE. "BREEDS
ELSEWHERE" INDICATES THAT
THE BIRD DOES NOT LIKELY
BREED IN YOUR PROJECT
AREA.)

# Bald Eagle Haliaeetus leucocephalus

This is not a Bird of Conservation Concern (BCC) in this area, but warrants attention because of the Eagle Act or for potential susceptibilities in offshore areas from certain types of development or activities.

Breeds Jan 1 to Aug 31

# Black Tern Chlidonias niger

This is a Bird of Conservation Concern (BCC) throughout its range in the continental USA and Alaska. <a href="https://ecos.fws.gov/ecp/species/3093">https://ecos.fws.gov/ecp/species/3093</a>

Breeds May 15 to Aug 20

## California Thrasher Toxostoma redivivum

This is a Bird of Conservation Concern (BCC) throughout its range in the continental USA and Alaska.

Breeds Jan 1 to Jul 31

## Clark's Grebe Aechmophorus clarkii

This is a Bird of Conservation Concern (BCC) throughout its range in the continental USA and Alaska.

Breeds Jun 1 to Aug 31

# Common Yellowthroat Geothlypis trichas sinuosa

This is a Bird of Conservation Concern (BCC) only in particular Bird Conservation Regions (BCRs) in the continental USA <a href="https://ecos.fws.gov/ecp/species/2084">https://ecos.fws.gov/ecp/species/2084</a>

Breeds May 20 to Jul 31

# Golden Eagle Aquila chrysaetos

This is not a Bird of Conservation Concern (BCC) in this area, but warrants attention because of the Eagle Act or for potential susceptibilities in offshore areas from certain types of development or activities.

https://ecos.fws.gov/ecp/species/1680

# Lawrence's Goldfinch Carduelis lawrencei

This is a Bird of Conservation Concern (BCC) throughout its range in the continental USA and Alaska.

https://ecos.fws.gov/ecp/species/9464

#### Marbled Godwit Limosa fedoa

This is a Bird of Conservation Concern (BCC) throughout its range in the continental USA and Alaska.

https://ecos.fws.gov/ecp/species/9481

# Nuttall's Woodpecker Picoides nuttallii

This is a Bird of Conservation Concern (BCC) only in particular Bird Conservation Regions (BCRs) in the continental USA <a href="https://ecos.fws.gov/ecp/species/9410">https://ecos.fws.gov/ecp/species/9410</a>

# Oak Titmouse Baeolophus inornatus

This is a Bird of Conservation Concern (BCC) throughout its range in the continental USA and Alaska. <a href="https://ecos.fws.gov/ecp/species/9656">https://ecos.fws.gov/ecp/species/9656</a>

# Short-billed Dowitcher Limnodromus griseus

This is a Bird of Conservation Concern (BCC) throughout its range in the continental USA and Alaska. https://ecos.fws.gov/ecp/species/9480

# Tricolored Blackbird Agelaius tricolor

This is a Bird of Conservation Concern (BCC) throughout its range in the continental USA and Alaska. <a href="https://ecos.fws.gov/ecp/species/3910">https://ecos.fws.gov/ecp/species/3910</a>

## Willet Tringa semipalmata

This is a Bird of Conservation Concern (BCC) throughout its range in the continental USA and Alaska.

Breeds Jan 1 to Aug 31

Breeds Mar 20 to Sep 20

Breeds elsewhere

Breeds Apr 1 to Jul 20

Breeds Mar 15 to Jul 15

Breeds elsewhere

Breeds Mar 15 to Aug 10

Breeds elsewhere

This is a Bird of Conservation Concern (BCC) throughout its range in the continental USA and Alaska.

Yellow-billed Magpie Pica nuttalli

Breeds Apr 1 to Jul 31

This is a Bird of Conservation Concern (BCC) throughout its range in the continental USA and Alaska. https://ecos.fws.gov/ecp/species/9726

# **Probability of Presence Summary**

The graphs below provide our best understanding of when birds of concern are most likely to be present in your project area. This information can be used to tailor and schedule your project activities to avoid or minimize impacts to birds. Please make sure you read and understand the FAQ "Proper Interpretation and Use of Your Migratory Bird Report" before using or attempting to interpret this report.

# Probability of Presence (■)

Each green bar represents the bird's relative probability of presence in the 10km grid cell(s) your project overlaps during a particular week of the year. (A year is represented as 12 4-week months.) A taller bar indicates a higher probability of species presence. The survey effort (see below) can be used to establish a level of confidence in the presence score. One can have higher confidence in the presence score if the corresponding survey effort is also high.

How is the probability of presence score calculated? The calculation is done in three steps:

- 1. The probability of presence for each week is calculated as the number of survey events in the week where the species was detected divided by the total number of survey events for that week. For example, if in week 12 there were 20 survey events and the Spotted Towhee was found in 5 of them, the probability of presence of the Spotted Towhee in week 12 is 0.25.
- 2. To properly present the pattern of presence across the year, the relative probability of presence is calculated. This is the probability of presence divided by the maximum probability of presence across all weeks. For example, imagine the probability of presence in week 20 for the Spotted Towhee is 0.05, and that the probability of presence at week 12 (0.25) is the maximum of any week of the year. The relative probability of presence on week 12 is 0.25/0.25 = 1; at week 20 it is 0.05/0.25 = 0.2.
- 3. The relative probability of presence calculated in the previous step undergoes a statistical conversion so that all possible values fall between 0 and 10, inclusive. This is the probability of presence score.

To see a bar's probability of presence score, simply hover your mouse cursor over the bar.

# Breeding Season (=)

Yellow bars denote a very liberal estimate of the time-frame inside which the bird breeds across its entire range. If there are no yellow bars shown for a bird, it does not breed in your project area.

# Survey Effort (I)

Vertical black lines superimposed on probability of presence bars indicate the number of surveys performed for that species in the 10km grid cell(s) your project area overlaps. The number of surveys is expressed as a range, for example, 33 to 64 surveys.

To see a bar's survey effort range, simply hover your mouse cursor over the bar.

## No Data (-)

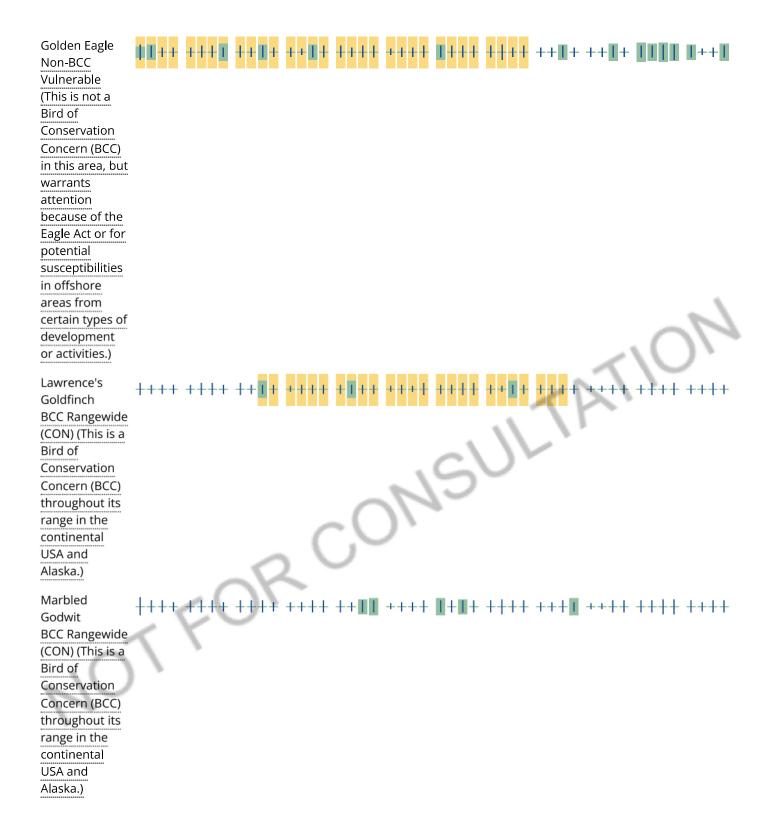
A week is marked as having no data if there were no survey events for that week.

# **Survey Timeframe**

Surveys from only the last 10 years are used in order to ensure delivery of currently relevant information. The exception to this is areas off the Atlantic coast, where bird returns are based on all years of available data, since data in these areas is currently much more sparse.











Tell me more about conservation measures I can implement to avoid or minimize impacts to migratory birds.

Nationwide Conservation Measures describes measures that can help avoid and minimize impacts to all birds at any location year round. Implementation of these measures is particularly important when birds are most likely to occur in the project area. When birds may be breeding in the area, identifying the locations of any active nests and avoiding their destruction is a very helpful impact minimization measure. To see when birds are most likely to occur and be breeding in your project area, view the Probability of Presence Summary. Additional measures or permits may be advisable depending on the type of activity you are conducting and the type of infrastructure or bird species present on your project site.

What does IPaC use to generate the migratory birds potentially occurring in my specified location?

The Migratory Bird Resource List is comprised of USFWS <u>Birds of Conservation Concern (BCC)</u> and other species that may warrant special attention in your project location.

The migratory bird list generated for your project is derived from data provided by the <u>Avian Knowledge Network (AKN)</u>. The AKN data is based on a growing collection of <u>survey, banding, and citizen science datasets</u> and is queried and filtered to return a list of those birds reported as occurring in the 10km grid cell(s) which your project intersects, and that have been identified as warranting special attention because they are a BCC species in that area, an eagle (<u>Eagle Act</u> requirements may apply), or a species that has a particular vulnerability to offshore activities or development.

Again, the Migratory Bird Resource list includes only a subset of birds that may occur in your project area. It is not representative of all birds that may occur in your project area. To get a list of all birds potentially present in your project area, please visit the <u>AKN Phenology Tool</u>.

# What does IPaC use to generate the probability of presence graphs for the migratory birds potentially occurring in my specified location?

The probability of presence graphs associated with your migratory bird list are based on data provided by the <u>Avian Knowledge Network (AKN)</u>. This data is derived from a growing collection of <u>survey</u>, <u>banding</u>, <u>and citizen science datasets</u>.

Probability of presence data is continuously being updated as new and better information becomes available. To learn more about how the probability of presence graphs are produced and how to interpret them, go the Probability of Presence Summary and then click on the "Tell me about these graphs" link.

## How do I know if a bird is breeding, wintering, migrating or present year-round in my project area?

To see what part of a particular bird's range your project area falls within (i.e. breeding, wintering, migrating or year-round), you may refer to the following resources: The Cornell Lab of Ornithology All About Birds Bird Guide, or (if you are unsuccessful in locating the bird of interest there), the Cornell Lab of Ornithology Neotropical Birds guide. If a bird on your migratory bird species list has a breeding season associated with it, if that bird does occur in your project area, there may be nests present at some point within the timeframe specified. If "Breeds elsewhere" is indicated, then the bird likely does not breed in your project area.

## What are the levels of concern for migratory birds?

Migratory birds delivered through IPaC fall into the following distinct categories of concern:

- 1. "BCC Rangewide" birds are <u>Birds of Conservation Concern</u> (BCC) that are of concern throughout their range anywhere within the USA (including Hawaii, the Pacific Islands, Puerto Rico, and the Virgin Islands):
- 2. "BCC BCR" birds are BCCs that are of concern only in particular Bird Conservation Regions (BCRs) in the continental USA; and
- 3. "Non-BCC Vulnerable" birds are not BCC species in your project area, but appear on your list either because of the <u>Eagle Act</u> requirements (for eagles) or (for non-eagles) potential susceptibilities in offshore areas from certain types of development or activities (e.g. offshore energy development or longline fishing).

Although it is important to try to avoid and minimize impacts to all birds, efforts should be made, in particular, to avoid and minimize impacts to the birds on this list, especially eagles and BCC species of rangewide concern. For more information on conservation measures you can implement to help avoid and minimize migratory bird impacts and requirements for eagles, please see the FAQs for these topics.

### Details about birds that are potentially affected by offshore projects

For additional details about the relative occurrence and abundance of both individual bird species and groups of bird species within your project area off the Atlantic Coast, please visit the <u>Northeast Ocean Data Portal</u>. The Portal also offers data and information about other taxa besides birds that may be helpful to you in your project review. Alternately, you may download the bird model results files underlying the portal maps through the <u>NOAA NCCOS Integrative Statistical Modeling and Predictive Mapping of Marine Bird Distributions and Abundance on the Atlantic Outer Continental Shelf project webpage.</u>

Bird tracking data can also provide additional details about occurrence and habitat use throughout the year, including migration. Models relying on survey data may not include this information. For additional information on marine bird tracking data, see the <u>Diving Bird Study</u> and the <u>nanotag studies</u> or contact <u>Caleb Spiegel</u> or <u>Pam Loring</u>.

### What if I have eagles on my list?

If your project has the potential to disturb or kill eagles, you may need to <u>obtain a permit</u> to avoid violating the Eagle Act should such impacts occur.

# Proper Interpretation and Use of Your Migratory Bird Report

The migratory bird list generated is not a list of all birds in your project area, only a subset of birds of priority concern. To learn more about how your list is generated, and see options for identifying what other birds may be in your project area, please see the FAQ "What does IPaC use to generate the migratory birds potentially occurring in my specified location". Please be aware this report provides the "probability of presence" of birds within the 10 km grid cell(s) that overlap your project; not your exact project footprint. On the graphs provided, please also look carefully at the survey effort (indicated by the black vertical bar) and for the existence of the "no data" indicator (a red horizontal bar). A high survey effort is the key component. If the survey effort is high, then the probability of presence score can be viewed as more dependable. In contrast, a low survey effort bar or no data bar means a lack of data and, therefore, a lack of certainty about presence of the species. This list is not perfect; it is simply a starting point for identifying what birds of concern have the potential to be in your project area, when they might be there, and if they might be breeding (which means nests might be present). The list helps you know what to look for to confirm presence, and helps guide you in knowing when to implement conservation measures to avoid or minimize potential impacts from your project activities, should presence be confirmed. To learn more about conservation measures, visit the FAQ "Tell me about conservation measures I can implement to avoid or minimize impacts to migratory birds" at the bottom of your migratory bird trust resources page.

# **Facilities**

# National Wildlife Refuge lands

Any activity proposed on lands managed by the <u>National Wildlife Refuge</u> system must undergo a 'Compatibility Determination' conducted by the Refuge. Please contact the individual Refuges to discuss any questions or concerns.

# Fish hatcheries

THERE ARE NO FISH HATCHERIES AT THIS LOCATION.

# Wetlands in the National Wetlands Inventory

Impacts to <u>NWI wetlands</u> and other aquatic habitats may be subject to regulation under Section 404 of the Clean Water Act, or other State/Federal statutes.

For more information please contact the Regulatory Program of the local <u>U.S. Army Corps of Engineers District</u>.

#### WETLAND INFORMATION IS NOT AVAILABLE AT THIS TIME

This can happen when the National Wetlands Inventory (NWI) map service is unavailable, or for very large projects that intersect many wetland areas. Try again, or visit the <u>NWI map</u> to view wetlands at this location.

#### **Data limitations**

The Service's objective of mapping wetlands and deepwater habitats is to produce reconnaissance level information on the location, type and size of these resources. The maps are prepared from the analysis of high altitude imagery. Wetlands are identified based on vegetation, visible hydrology and geography. A margin of error is inherent in the use of imagery; thus, detailed on-the-ground inspection of any particular site may result in revision of the wetland boundaries or classification established through image analysis.

The accuracy of image interpretation depends on the quality of the imagery, the experience of the image analysts, the amount and quality of the collateral data and the amount of ground truth verification work conducted. Metadata should be consulted to determine the date of the source imagery used and any mapping problems.

Wetlands or other mapped features may have changed since the date of the imagery or field work. There may be occasional differences in polygon boundaries or classifications between the information depicted on the map and the actual conditions on site.

#### Data exclusions

Certain wetland habitats are excluded from the National mapping program because of the limitations of aerial imagery as the primary data source used to detect wetlands. These habitats include seagrasses or submerged aquatic vegetation that are found in the intertidal and subtidal zones of estuaries and nearshore coastal waters. Some deepwater reef communities (coral or tuberficid worm reefs) have also

been excluded from the inventory. These habitats, because of their depth, go undetected by aerial imagery.

## Data precautions

Federal, state, and local regulatory agencies with jurisdiction over wetlands may define and describe wetlands in a different manner than that used in this inventory. There is no attempt, in either the design or products of this inventory, to define the limits of proprietary jurisdiction of any Federal, state, or local government or to establish the geographical scope of the regulatory programs of government agencies. Persons intending to engage in activities involving modifications within or adjacent to wetland areas should seek the advice of appropriate federal, state, or local agencies concerning specified agency regulatory programs and proprietary jurisdictions that may affect such activities.



#### **Class VI UIC Project Plan Submissions**

This submission is for:

Project ID: R09-CA-0010

Project Name: Mullen Storage Project

Current Project Phase: Pre-Injection Prior to Construction

#### **Testing and Monitoring**

Are You Making a Testing and Monitoring Plan Submission at this Time: Yes

Reason for Project Plan Submission: Permit Application Submission

Project Plan Upload

Attach the Testing and Monitoring Plan: <a href="https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no">https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no</a> wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/ProjPlan-05-

03-2022-1838/Attachment--C----CTV--III-----Testing--Monitoring--plan.pdf

Appendices and Supporting Materials Upload

Attach Any Supporting Documentation for the Testing and Monitoring Plan: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-

0010/Phase1-PreConstruction/ProjPlan-05-03-2022-1838/CTV--III-----QASP.pdf

#### Injection Well Plugging

Are You Making an Injection Well Plugging Plan Submission at this Time: Yes

Reason for Project Plan Submission: Permit Application Submission

Project Plan Upload

Attach the Injection Well Plugging Plan: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-PreConstruction/ProjPlan-05-

03-2022-1838/Attachment--D-----CTV--III-----Injection--well--Plugging--Plan.pdf

Appendices and Supporting Materials Upload

#### **PISC and Site Closure**

Are You Making a Post-Injection Site Care and Site Closure Plan Submission at this Time: Yes

Reason for Project Plan Submission: Permit Application Submission

Project Plan Upload

Attach the Post-Injection Site Care and Site Closure Plan: <a href="https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-10-2016/phase1-2016/phase1

PreConstruction/ProjPlan-05-03-2022-1838/Attachment--E-----CTV--III-----PISC SC.pdf

Appendices and Supporting Materials Upload

### **Emergency and Remedial Response**

Are You Making an Emergency and Remedial Response Plan Submission at this Time: Yes

Reason for Project Plan Submission: Permit Application Submission

Project Plan Upload

Attach the Emergency and Remedial Response Plan: https://gsdt.pnnl.gov/alfresco/service/velo/getFile/no\_wiki/shared/Submissions/R09-CA-0010/Phase1-

PreConstruction/ProjPlan-05-03-2022-1838/Attachment--F----CTV--III-----ERR.pdf

Appendices and Supporting Materials Upload

#### **Complete Submission**

Authorized submission made by: Travis Hurst

For confirmation a read-only copy of your submission will be emailed to: travis.hurst@crc.com

# ATTACHMENT C: TESTING AND MONITORING PLAN 40 CFR 146.90

#### CTV III

# **Facility Information**

Facility Name: CTV III

Facility Contact: William Chessum / Technical Manager

(562) 999-8380 / William.chessum@crc.com

Well location:

This Testing and Monitoring Plan describes how CTV will monitor the project site pursuant to 40 CFR 146.90. The monitoring data will be used to demonstrate that the wells are operating as planned, the carbon dioxide plume and pressure front are moving as predicted, and that there is no endangerment to USDWs. In addition, the monitoring data will be used to validate and adjust the computational model used to predict the distribution of the CO<sub>2</sub> within the storage zone, supporting AoR re-evaluations and a non-endangerment demonstration.

Results of the testing and monitoring activities described below may trigger action according to the Emergency and Remedial Response Plan.

#### Quality assurance procedures

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities, required pursuant to 146.90(k), is provided in the Appendix to this Testing and Monitoring Plan.

#### Reporting procedures

CTV will report the results of all testing and monitoring activities to the EPA in compliance with the requirements under 40 CFR 146.91.

#### Carbon Dioxide Stream Analysis [40 CFR 146.90(a)]

CTV will analyze the  $CO_2$  stream during the operation period to yield data representative of its chemical and physical characteristics and to meet the requirements of 40 CFR 146.90(a). Samples will be collected and analyzed quarterly, starting three months after the start of injection and every three months thereafter.

CTV is evaluating several sources of CO<sub>2</sub> as injectate for the project. Notification will be sent to the EPA prior to switching or adding CO<sub>2</sub> sources, at which time the sampling procedures can be reassessed.

## Sampling location and frequency

 $CO_2$  injectate samples will be taken between the final compression stage and the wellhead. Sampling will take place three months after the date of authorization of injection and every three months thereafter.

CTV will increase the frequency and collect additional samples if the following occurs:

- 1. Significant changes in the chemical or physical characteristics of the CO<sub>2</sub> injectate, such as a change in the CO<sub>2</sub> injectate source; and
- 2. Facility or injector downtime is greater than thirty days.

### Analytical parameters

CTV will analyze the water content and injectate the constituents identified in Table 1 using the methods listed. An equivalent method may be employed with the prior approval of the UIC Program Director.

Table 1. Summary of analytical parameters for CO<sub>2</sub> stream.

Parameter	Analytical Method(s)	
Oxygen, Argon and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD	
Nitrogen	ISBT 4.0 (GC/DID) GC/TCD	
Carbon Monoxide	ISBT 5.0 (Colorimetric) ISBT 4.0 (GC/DID)	
Total Hydrocarbons	ISBT 10.0 THA (FID)	
Ammonia	ISBT 6.0 (DT)	
Ethanol	ISBT 11.0 (GC/FID)	
Oxides of Nitrogen	ISBT 7.0 Colorimetric	
Methane	ISBT 10.1 (FID)	
Hydrogen Sulfide and Sulfur Dioxide	ISBT 14.0 (GC/SCD)	
CO <sub>2</sub> purity	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD	
δ13C	Isotope ratio mass spectrometry	

## Sampling methods

 $CO_2$  stream sampling will occur in the last compressor station prior to being sent to the injector. A sampling station will be installed to facilitate collection of samples into a container. Sample containers will have a chain of custody form and will be labeled appropriately.

## Laboratory to be used/chain of custody and analysis procedures

Samples will be sent to, and analysis conducted by is a state certified laboratory. The current plan is to use Eurofins TestAmerica (Eurofins) at 880 Riverside Parkway in Sacramento, CA. The laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 3.

Eurofins has a chain of custody procedure that includes the following.

- 1. Sample date
- 2. Sample description
- 3. Sample type
- 4. Relinquished by and received by signature
- 5. Sampler name
- 6. Location information

# Continuous Recording of Operational Parameters [40 CFR 146.88(e)(1), 146.89(b) and 146.90(b)]

CTV will install and use continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; the annulus fluid volume added; and the temperature of the  $CO_2$  stream, as required by 40 CFR 146.88(e)(1), 146.89(b), and 146.90(b).

#### Monitoring location and frequency

CTV will perform the activities identified in Table 2 to monitor operational parameters and verify internal mechanical integrity of the injection well. All monitoring will take place at the locations and frequencies shown in the table.

Monitoring for the parameters, except for annulus fluid volume, will be continuous with a 10 second sampling and 30 second recording frequency for both active and shut-in periods. This will be adequate to monitor for changes in the wellbore and the reservoir.

Table 2. Sampling devices, locations, and frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection pressure	Pressure Gauge	Surface and Downhole	10 seconds	30 seconds
Injection rate	Flowmeter	Surface	10 seconds	30 seconds
Injection volume	Calculated	Surface	10 seconds	30 seconds
Annular pressure	Pressure Gauge	Surface	10 seconds	30 seconds
Annulus fluid volume		Surface	4 hours	24 hours
Temperature	Temperature Gauge	Surface and Downhole	10 seconds	30 seconds
Temperature	DTS	Along wellbore to packer	10 seconds	30 seconds

#### Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

#### **Monitoring Details**

# **Injection Rate and Pressure Monitoring**

Injection pressure (gauge), temperature and flow rate (flow meter) will be continuously monitored and recorded by the CTV Central Command Facility (CCF). Injection rate and pressure

limitations will be implemented to ensure adherence to the maximum allowable bottomhole injection pressure of 90% of the injection zone's fracture pressure. Pressure and temperature gauges will be calibrated as shown in QASP Table 6.

#### **Calculation of Injection Volumes**

The volume of CO<sub>2</sub> injected into will be calculated from the injection flow rate and CO<sub>2</sub> density. Density of CO<sub>2</sub> injected into will be calculated using PVTP, a fluid thermodynamics package, developed by Petroleum Experts Ltd. PVTP is an industry standard software package that has been used extensively in CO<sub>2</sub> EOR applications to accurately model and match CO<sub>2</sub> PVT properties over a wide range of temperatures and pressures.

#### **Annular Pressure Monitoring**

Annulus pressure is monitored continuously (every 10 seconds) with a surface pressure sensor to monitor for integrity of the casing, packer, and tubing. The annulus will be filled with a non-corrosive and incompressible aqueous packer fluid. Deviations in the annular pressure above certain thresholds may indicate a well integrity issue that will be investigated. Thresholds and alarms will be defined during pre-operational testing.

The surface pressure that will be maintained on the casing-tubing annulus for each injector is listed in Table 3 based on starting and ending injection conditions. The minimum surface pressure is 100 psi to ensure that any drop in pressure or annular fluid level is identified with the SCADA alarming system. The pressures are also found in the Appendix: Operating Procedure document with additional context.

Table 3. Injector Annulus Pressure Limits.

Well Name	Min Pressure (psi)	re (psi) Max Pressure (psi)	
C1	100	315	
C2	100	605	
E1	100	216 396	
E2	100		
W1	100	210	
W2	100	449	

#### Injection Rate

The injection rate will be monitored with a Coriolis flowmeter. The meter will be calibrated for the expected flow rate range using accepted standards and will be accurate to within 0.1 percent.

#### **Corrosion Monitoring**

To meet the requirements of 40 CFR 146.90(c), CTV will monitor well materials during the operation period for loss of mass, thickness, cracking, pitting, and other signs of corrosion to ensure that the well components meet the minimum standards for material strength and performance. CTV will monitor corrosion using corrosion coupons and collect samples according to the description below.

#### Monitoring location and frequency

Monitoring will be conducted quarterly during the injection period, starting three months after injection begins and quarterly thereafter. Monitoring results will be documented and submitted to the EPA as per 40 CFR 146.91 (a)(7). CTV will continually update the corrosion monitoring plan as data is acquired.

## Sample description

Samples of the materials used in the construction of the surface flowline equipment, wellheads, and injection and monitoring well tubulars that are exposed to CO<sub>2</sub> injectate will be monitored for corrosion using corrosion coupons. Representative materials (Table 3) will be weighed, measured, and photographed prior to installation. General construction materials for pipeline, tubing and wellhead are shown in Table 4. Updated materials will be provided prior to injection as part of pre-operational testing.

Table 4. List of equipment coupon with material of construction.

Equipment Coupon	Material of Construction	
Pipeline	Carbon Steel	
Casing (flow-wetted)	Chrome Alloy	8
Tubing	Chrome Alloy	
Wellhead	Chrome Alloy	-

#### Monitoring details

The corrosion coupons will be located in the pipeline that feeds CO<sub>2</sub> injectate to the injectors. Quarterly the coupons will be sent to a lab and photographed, measured, visually inspected, and weighed to a resolution of 0.1 milligram. The samples will be handled and assessed in accordance with ASTM G1-03.

A detected corrosion rate of greater than 0.3 mils/year will initiate consultation with the EPA. In addition, a casing inspection log may be run to assess the thickness and quality of the casing if the corrosion rate exceeds 0.3 mils/year.

#### **Above Confining Zone Monitoring**

CTV will monitor groundwater quality and geochemical changes above the confining zone during the operation period to meet the requirements of 40 CFR 146.90(d). Monitoring above the confining zone will include the following:

- 1. Undifferentiated non-marine- lowermost USDW will be monitored between approximately feet MD in the USDW monitoring wells.
- 2.

#### Monitoring location and frequency

Table 4 shows the planned monitoring methods, locations, and frequencies for ground water quality and geochemical monitoring above the confining zone. Figure 1 shows the location for the monitoring well locations with respect to the AoR. The wells are located within the project boundary, and CTV has obtained surface access for the duration of the project.

#### <u>Undifferentiated Non-Marine</u>

CTV will monitor the lowermost USDW in the undifferentiated non-marine sediments. Monitoring will include pressure, temperature, and fluid sampling. Leakage to the lowermost USDW would increase the aquifer pressure and change the composition of the formation water (increased CO<sub>2</sub> concentration). Based on having groundwater less than 10,000 ppm TDS, the proposed monitoring zone is a USDW. However, the water supply wells in the AoR are completed at much shallower depths that are above the base of fresh water, which is at about 1,000 ft MD. Monitoring of the lowermost USDW is more protective than monitoring the freshwater aquifers because impacts would occur in the lowermost USDW before the freshwater aquifers.

The locations of groundwater monitoring wells are often based on the local groundwater gradient. There are very few groundwater supply wells in this area because there is a plentiful supply of surface water. Therefore, groundwater gradient maps don't show any water level elevations this area. Thus, groundwater gradients are not expected to be significant due to the lack of pumping. The locations of the two monitoring wells are planned on opposite sides of the CO<sub>2</sub> plume to the northeast and southwest within reasonable proximity to the injection wells and well identified as requiring a corrective action plan.

Prior to injection, an updated baseline analysis will be completed for the USDW monitoring well. Future results will be compared against these baseline results for significant changes or anomalies. In particular, pH will be monitored as a key indicator of CO<sub>2</sub> presence.

Additional groundwater monitoring wells will be drilled to assess and monitor the lowermost USDW if the following occurs:

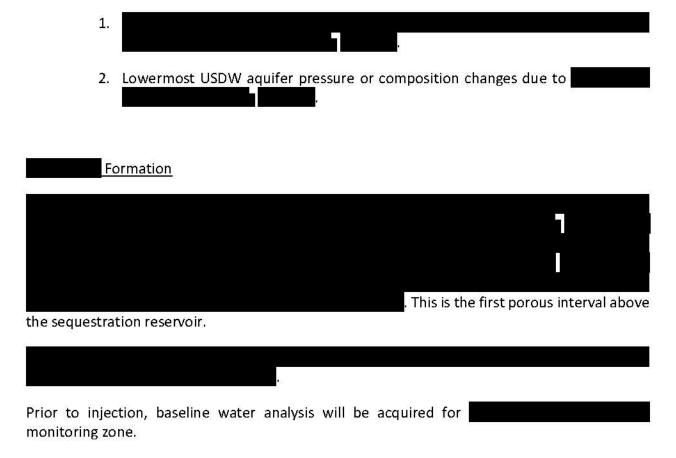


Table 5. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	<b>Monitoring Activity</b>	Monitoring Location(s)	Frequency	Depth
Undifferentiated Non-marine	Fluid Sampling	USDW Monitoring Well	Quarterly	MD/TVD
	Pressure/Temperature	USDW Monitoring Well	Continuously	
	Pressure/Temperature		Continuously	MD/D/D
;	Fluid Sampling		Quarterly	MD/TVD



## Analytical parameters

Table 6 identifies the parameters to be monitored and the analytical methods CTV will use. Detection limits and precision are shown in QASP Table 3.

Table 6. Summary of analytical and field parameters for water samples from the USDW monitoring well and monitoring well.

Parameters	Analytical Methods			
Undifferentiated Non-marine - Lowermost USDW				
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, Zn, Tl)	ICP-MS EPA Method 6020			
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OES EPA Method 6010B			
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0			
Dissolved CO <sub>2</sub>	Coulometric titration, ASTM D513-11			
δ13C	Isotope ratio mass spectrometry			
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)			
Oxygen, Argon and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD			
Total Dissolved Solids	Gravimetry; Method 2540 C			
Alkalinity	Method 2320B			
pH (field)	EPA 150.1			
Specific Conductance (field)	SM 2510 B			
Temperature (field)	Thermocouple			

#### Sampling methods

Samples will be collected using the following procedures:

- 1. Depth and elevation measurements for water level taken.
- 2. Wells will be purged such that existing water in the well is removed and fresh formation water is sampled.
- 3. Samples collected by lowering cleaned equipment downhole. Field measurements taken for pH, temperature, conductance, and dissolved oxygen.
- 4. Samples preserved and sent to lab as per chain of custody procedure.
- 5. Closure of well.

## Laboratory to be used/chain of custody procedures

Samples will be sent to, and analysis conducted by is a state certified laboratory. The current plan is to use Eurofins TestAmerica (Eurofins) at 880 Riverside Parkway in Sacramento, CA. The

laboratory has all the necessary equipment, experience, and certifications to complete the analysis. The detection limit and precision can be found in the QASP, Table 3.

Eurofins has a chain of custody procedure that includes the following.

- 1. Sample date
- 2. Sample description
- 3. Sample type
- 4. Relinquished by and received by signature
- 5. Sampler name
- 6. Location information

#### Mechanical Integrity Testing

CTV will conduct at least one test periodically during the injection phase to verify external mechanical integrity as required at 146.89(c) and 146.90. MITs on the injectors and monitoring wells will be performed annually, within 30 days of the commencement of the injection date, by one of two methods in Table 6. If CTV elects to conduct an alternate MIT, notification that includes the test and a description will be sent to the EPA for approval.

#### Testing location and frequency

Table 7. MITs.

Test Description	Location	
Temperature (DTS)	Along wellbore via DTS	
Temperature Log	Along wellbore via wireline well log	

#### Distributed Temperature Sensing (DTS)

DTS is a fiber optic continuous temperature monitoring system that will measure the injector and monitoring wells annular temperature along the tubing. This will be used to assess the mechanical integrity of the well.

The following is procedures to utilize DTS for mechanical integrity analysis for an injector:

1. Establish baseline temperature profile that defines the natural gradient along the well.

- 2. During injection, record the temperature profile for 6 hours prior to shutting in the well. Stop injection and record the temperature for sufficient time to allow cooling.
- 3. Start injection and record the temperature profile for 6 hours.
- 4. Compare the baseline analysis to the time-lapse data for assessment of temperature anomalies that may indicate a well failure.

#### Temperature Logging Testing details

CTV will follow the following procedures for MIT temperature logging:

- Stabilize injection for 24 hours prior to running the temperature log. If possible, the
  wireline speed will be limited to 20 feet per minute or less. The temperature sensor
  should be located as close to the bottom of the tool string as possible (logging
  downhole).
- 2. Run a temperature survey from 200 feet above point reachable in the well, while injecting at a rate that allows for safe operations.
- 3. Shut-in well and run multiple temperature surveys with 4 hours between runs.
- 4. Assess the acquired time lapse temperature profiles. As the well cools, the temperature profile is compared to the baseline. External integrity issues present themselves anomalies when compared to the baseline.
- 5. Evaluate data to determine if additional passes are needed for interpretation. Should CO<sub>2</sub> migration be interpreted in the topmost section of the log, additional logging runs over a higher interval will be required to find the top of migration.

#### Pressure Fall-Off Testing

CTV will perform pressure fall-off tests during the injection phase every five years as described below to meet the requirements of 40 CFR 146.90(f).

#### Testing location and frequency

The main benefit of pressure fall-off testing is to assess injectivity, reservoir flow boundary distances and reservoir pressures. The fall-off test will be done on the two injectors every five years.

#### Testing details

The following procedure will be followed:

- 1. Injection rate will be held constant prior to shut in. The injection rate will be high enough to produce a pressure buildup that will result in valid test data. The maximum operating pressure will not be exceeded.
- 2. The pressure falloff analysis will use several months of preceding injection data.
- 3. The test well should be shut-in at the wellhead to minimize wellbore storage and afterflow.
- 4. Upon shutting in the injector, surface and bottom-hole pressure and temperature measurements will be taken continuously every ten seconds. If there are offset injectors, rates will be held constant and recorded during the test.
- 5. The fall-off portion of the test will be conducted for a length of time sufficient that the pressure is no longer influenced by wellbore storage or skin.
- 6. Maintain accurate rate records for the test well and any offset wells completed in the same injection interval.
- 7. A report containing the pressure falloff data and interpretation of the reservoir pressure will be submitted to the EPA within 90 days of the test.

Pressure sensors used for this test will be the wellhead gauges and a downhole gauge for the pressure falloff test. Each gauge will meet or exceed ASME B 40.1 Class 2A that provides 0.5% accuracy. CTV will refer to EPA Region 9 UIC Pressure Falloff Requirements for additional procedures such as planning and evaluation.

#### **Carbon Dioxide Plume and Pressure Front Tracking**

CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure during the operation period to meet the requirements of 40 CFR 146.90(g).

#### Plume monitoring location and frequency

Table 6 presents the methods that CTV will use to monitor the position of the  $CO_2$  plume, including the activities, locations, and frequencies. The parameters to be analyzed as part of fluid sampling in the injection zone and associated analytical methods are presented in Table 7. Quality assurance procedures for these methods are presented in Section B – Data Generation and Acquisition of the QASP.

Figure 2 shows the location of the wells that will monitor the  $CO_2$  plume directly in . These wells will actively monitor the development of the  $CO_2$  plume upon the initiation of injection. If the plume development is not consistent with computation modeling

results, CTV will assess whether additional monitoring of the plume is necessary. Determination for plume monitoring changes will be made in consultation with the UIC Program Director and would trigger an AoR reevaluation, per the AoR and Corrective Action Plan.



#### Plume monitoring details

Fluid sampling (quarterly), pressure and temperature monitoring will be conducted for direct measurement of the plume. This will provide data on plume location but more importantly, the CO<sub>2</sub> content/concentration of the plume. The parameters to be analyzed for fluid sampling are presented in Table 9.

The DTS from the two monitoring wells will provide continuous temperature from packer to surface.

As discussed in the AoR and Corrective Action Plan, 83% of the post-shut-in injected  $CO_2$  will remain as super-critical. Fluid samples will be taken, and CTV expects that there will be minor changes to pH, dissolved  $CO_2$ , and water density.

Indirect plume monitoring will include pulse neutron logs (PNL) to understand  $CO_2$  saturation changes through time. Prior to injection, a pulse neutron log will be run as a baseline. A PNL will be run on the monitoring wells every two years during the injection phase.

Table 8. Plume monitoring activities.

DIRECT PLUME MONITORING			Depths
	Fluid Sampling	Quarterly	
	Pressure and temperature	Continuously	
INDIRECT PLUME	MONITORING		
	Pulse Neutron Logging	Every two years from start of injection.	

Table 9. Summary of analytical and field parameters for fluid sampling in the injection zone

Parameters	Analytical Methods		
	*		
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, ZN, Tl)	ICP-MS EPA Method 6020		
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OES EPA Method 6010B		
Anions (Br, Cl, F, NO3, SO4)	lon Chromatography, EPA Method 300.0		
Dissolved CO <sub>2</sub>	Coulometric titration ASTM D513-11		
813C	Isotope ratio mass spectrometry		
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)		
Oxygen, Argon and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD		
Total Dissolved Solids	Gravimetry; Method 2540 C		
Alkalinity	Method 2320B		
pH (field)	EPA 150.1		
Specific Conductance (field)	SM 2510 B		
Temperature (field)	Thermocouple		

## Pressure-front monitoring location and frequency

Table 10 presents the methods that CTV will use to monitor the position of the pressure front, including the activities, locations, and frequencies CTV will employ. Quality assurance procedures for these methods are presented in Section B – Data Generation and Acquisition of the QASP.

The pressure increase front defining the AoR boundary reaches its maximum extent 14 years into injection in the project. Pressure front will be monitored with 2 wells within the  $CO_2$  plume, and an additional well to the East of the project outside of the AoR in order to track the pressure change in the reservoir and ensure it is similar to that predicted by computational modeling. Monitoring well locations with respect to plume development through time are shown in Figure 3.



Monitoring well pressure development based on computational is modeled in Figure 4. Note that the reservoir pressure after five years is stable. This is due to the high amount of  $CO_2$  that remains super-critical and low quantity of  $CO_2$  that will be soluble in either the oil or water phases.

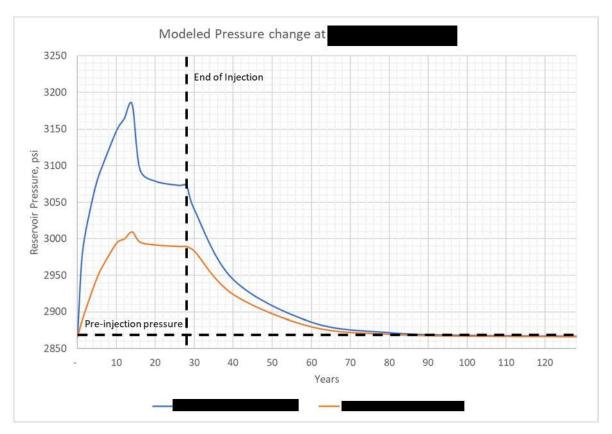


Figure 4: Modeled pressure at period and 100 years post injection during the injection

## Pressure-front monitoring details

Direct pressure monitoring of the plume will be achieved through installation of pressure gauges in monitoring wells CTV will compare the pressure and rate increase from the computational model to the monitoring data to validate computational modeling results and identify operational discrepancies, ensuring suitable definition of the AoR and plume throughout the life of the project.

Table 10. Pressure-front monitoring activities.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency
DIRECT PRESSURE-FROM	IT MONITORING		
	Pressure and temperature monitoring	ı	Continuous
INDIRECT PRESSURE-FR	ONT MONITORING		<del>-</del>
All formations	Seismicity	AoR	Continuous

## **Induced Seismicity and Fault Monitoring**

CTV will monitor seismicity with surface and shallow borehole seismometers in the AoR. The seismometers will be able to detect events with a magnitude 0 to 0.5 and will be installed one year prior to injection to provide baseline seismicity. In addition, CTV will monitor the Northern California Earthquake Data Center (NCEDC) network for seismic events. Historical seismicity within the area will be accounted for in the baseline assessment.

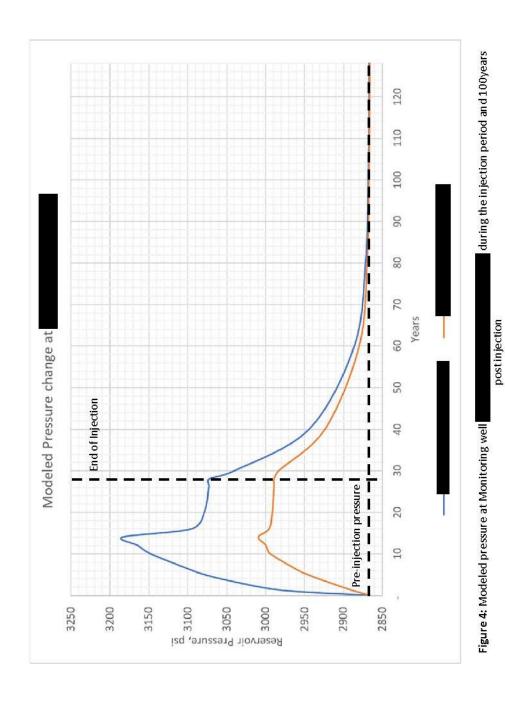
#### Appendix: Quality Assurance and Surveillance Plan

See Quality Assurance and Surveillance Plan









## ATTACHMENT D: INJECTION WELL PLUGGING PLAN 40 CFR 146.92(b)

#### **CTV III**

#### **Facility Information**

Facility Name: CTV III

Facility Contact: William Chessum / Technical Manager

(562) 999-8380 / William.chessum@crc.com

Location:

CTV will conduct injection well plugging and abandonment according to the procedures below. The proposed injection well plugging plan will ensure that the proposed materials and procedures for injection well plugging are appropriate to the well's construction and the site's geology and geochemistry.

#### Planned Tests or Measures to Determine Bottom-Hole Reservoir Pressure

Before beginning the plugging and abandonment process, the pressure used to squeeze the cement will be determined from the bottom hole pressure gauge. During plugging operations, the weighted cement slurry displacement fluids will be overbalanced to the reservoir pressure ensuring that no reservoir fluids will be able to enter the wellbore during cementing operations.

## <u>Planned External Mechanical Integrity</u> Tests

CTV will conduct at least one external mechanical integrity prior to plugging the injection well as required by 40 CFR 146.92(a).

A temperature log will be run over the entire depth of each sequestration well. Data from the logging runs will be evaluated for anomalies in the temperature curve, which would be indicative of fluid migration out of the injection zone. Data will be compared to the data from temperature logs performed prior to injection of CO2. Deviations between the temperature log performed before, after and during injection may indicate issues related to the integrity of the well casing or cement.

#### <u>Information on Plugs</u>

CTV will use the materials and methods noted in *Appendix C-1: Injection and Monitoring Well Schematics* to plug the injection well. This appendix provides proposed abandonment well schematics and tabulated

descriptions of all abandonment cement plugs for all injection and monitoring wells associated with the project.

The cementing design will consider reservoir temperature and pressure and will ensure compatibility with injectate and formation fluid geochemistry. The cement formulation and required certification documents will be submitted to the agency with the well plugging plan. The owner or operator will report the wet density and will retain duplicate samples of the cement used for each plug.

A Portland cement blend, such as Class G, will be utilized that has a minimum 1,000 psi compressive strength and a maximum liquid permeability of 0.1 mD. The wells will have this cement placed inside casing from the plugback depth of the well to surface. The cement will be set in plug segments per CTV's standard procedures.

#### **Narrative Description of Plugging Procedures**

#### Notifications, Permits, and Inspections

In compliance with 40 CFR 146.92(c), CTV will notify the regulatory agency at least 60 days before plugging the well and provide an updated Injection Well Plugging Plan, if applicable.

#### **Plugging Procedures**

The following plugging procedures are planned assuming a coiled tubing unit (CTU) is utilized for cement plug placement after all completion equipment is removed. The placement method may vary depending on the type of service equipment used. For instance, a maintenance rig may place the cement plug of same specification at same depths using jointed pipe and achieve the same result.

- 1. Bottom hole pressure from downhole pressure gauge is recorded and kill fluid density is calculated.
- 2. Kill fluid of appropriate density to prevent fluid inflow to the wellbore is circulated throughout the wellbore, and the well is observed to ensure static conditions.
- Well equipment is removed from the casing, and the well is cleaned out to TD during rig operations. Kill fluid is added to the wellbore to account for displacement of equipment that is removed, and the well is again observed to ensure static conditions.
- 4. The CTU runs in the hole to TD and begins placing cement in the casing. The coiled tubing is kept about 100' inside of the cement plug and is pulled up-hole while cementing operations continue. Once the full plug is placed, the coiled tubing is pulled above the plug and the well is circulated to ensure the depth of the top of the plug. The tubing is then pulled up-hole while operations are paused to wait on cement. Once the cement has "set", the coiled tubing is run back in the hole to witness the depth and hardness of the plug before initiating the next cemented plug interval. This process is repeated until cement is placed to surface.

## ATTACHMENT E: POST-INJECTION SITE CARE AND SITE CLOSURE PLAN 40 CFR 146.93(a)

#### **CTV III**

#### **Facility Information**

Facility name: CTV III

Facility contact: William Chessum / Technical Manager

(562) 999-8380 / William.chessum@crc.com

Location:

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Carbon TerraVault Holdings, LLC (CTV) will perform to meet the requirements of 40 CFR 146.93. CTV will monitor ground water quality and track the position of the carbon dioxide plume and pressure front for 50 years post injection. CTV will not cease post-injection monitoring until a demonstration of non-endangerment of USDWs has been approved by the UIC Program Director pursuant to 40 CFR 146.93(b)(3). Following approval for site closure, CTV will plug all monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

## Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]

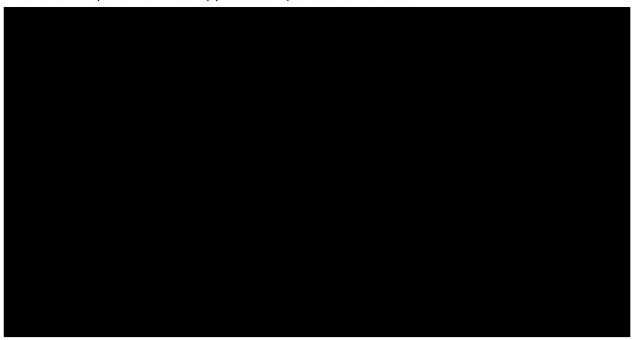
Based on the computational modeling, pressure in the injection area is expected to stabilize approximately 50 years after injection ceases. Injection limits will be based on the fracture pressure of the Additional information on the projected post-injection pressure declines and differentials is presented in the permit application, and the AoR and Corrective Action Plan.

#### Discussion

The storage reservoir will be operated such that the bottom hole injection pressures will not exceed the fracture pressure of the reservoir with a 10% safety factor.

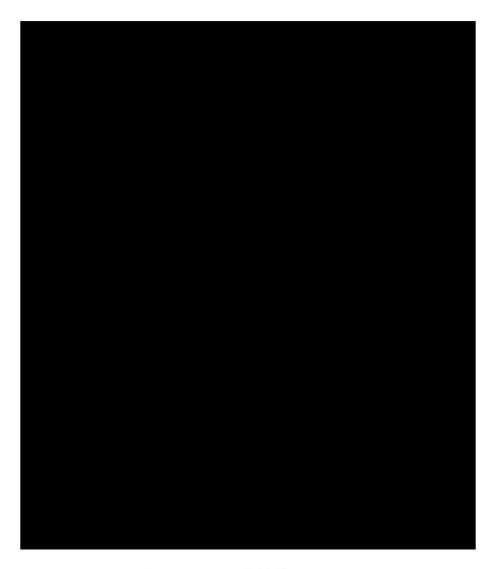
The pressure near the injection site is approximately 2860 psi prior to the start of injection. As shown in Figure 1 the pressure at the injection site peaks 14 years into injection with 3184psi modeled to be seen at the monitoring well location M2. Once injection ceases, the pressure is expected to drop fairly rapidly, with pressure dropping down to 2950 psi at the monitoring well

M2 within 10 years of the end of injection. 50 years after the end of injection the pressure in the reservoir is expected be back approximately to initial conditions.



# Predicted Position of the CO<sub>2</sub> Plume and Associated Pressure Front at Site Closure [40 CFR 146.93(a)(2)(ii)]

Figure 2 shows the predicted maximum extent of the plume and pressure front during the PISC timeframe. This map is based on the final AoR delineation modeling results submitted pursuant to 40 CFR 146.84. Figures 3 and 4 show the development of the CO2 plume during the injection period and after the cessation of injection. 52 years after the cessation of injection, the CO2 plume has largely stabilized, and no further movement is expected.



#### Post-Injection Monitoring Plan [40 CFR 146.93(b)(1)]

Monitoring during the post-injection phase will include a combination of groundwater pressure, fluid composition and storage zone pressure as described in the following sections and will meet the requirements of 40 CFR 146.93(b)(1). The results of all post-injection phase testing and monitoring will be submitted annually, within 90 days, as described under "Schedule for Submitting Post-Injection Monitoring Results," below.

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities during the injection and post injection phases is provided in the Appendix to the Testing and Monitoring Plan.

Post-injection monitoring will include a combination of groundwater monitoring, and storage zone pressure monitoring. Pressure monitoring of the storage reservoir will monitor for pressure stabilization. This is the best method to confirm confinement of the reservoir. If pressure in the reservoir trends lower post injection and is inconsistent when compared to computational modeling results, CTV will assess for potential leakage.

Throughout the AoR there are USDWs. As such, ongoing groundwater monitoring of the USDWs will assess potential impacts. Groundwater samples will be analyzed annually for indicators of CO<sub>2</sub> movement into the USDWs.

CTV has obtained surface access rights for the duration of the project.

## Monitoring Above the Confining Zone

Table 1 presents the monitoring methods, locations, and frequencies for monitoring above the confining zone. Table 2 identifies the parameters to be monitored and the analytical methods CTV will employ.

Table 1. Monitoring of ground water quality and geochemical changes above the confining zone.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency	Depth (feet)
	Fluid sampling	USDW Monitoring Well	AoR	Annually	
	Pressure and Temperature	USDW Monitoring Well	AoR	Continuously	
	Fluid sampling	D1	AoR	Annually	
	Pressure and Temperature Monitoring	D1	AoR	Continuously	

Table 2. Summary of analytical and field parameters for ground water samples.

Parameters	Analytical Methods
USDW and	
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, ZN, Tl)	ICP-MS EPA Method 6020
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OES EPA Method 6010B
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0
Dissolved CO2	Coulometric titration ASTM D513-11
δ13C	Isotope ratio mass spectrometry
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)

Parameters	Analytical Methods
Oxygen, Argon and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD
Total Dissolved Solids	Gravimetry; Method 2540 C
Alkalinity	Method 2320B
pH (field)	EPA 150.1
Specific Conductance (field)	SM 2510 B
Temperature (field)	Thermocouple

Table 3. Sampling and recording frequencies for continuous monitoring.

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
During active injection	Pressure Gauge	USDW Monitoring Well	5 hours	5 hours
Post injection	Pressure Gauge	USDW Monitoring Well	12 hours	12 hours

#### Notes:

- Sampling frequency refers to how often the monitoring device obtains data from the well for a particular parameter. For example, a recording device might sample a pressure transducer monitoring injection pressure once every two seconds and save this value in memory.
- Recording frequency refers to how often the sampled information gets recorded to digital format (such as a computer hard drive). For example, the data from the injection pressure transducer might be recorded to a hard drive once every minute.

#### Carbon Dioxide Plume and Pressure Front Tracking [40 CFR 146.93(a)(2)(iii)]

CTV will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure.

Table 4 presents the direct and indirect methods that CTV will use to monitor the CO<sub>2</sub> plume, including the activities, locations, and frequencies CTV will employ. The parameters to be analyzed as part of fluid sampling in the control (and associated analytical methods) are presented in Table 5.

Table 6 presents the direct and indirect methods that CTV will use to monitor the pressure front, including the activities, locations, and frequencies CTV will employ.

Fluid sampling will be performed as described in B.1. of the QASP; sample handling and custody will be performed as described in B.3. of the QASP; and quality control will be ensured using the methods described in B.5. of the QASP.

Table 4. Post-injection phase plume monitoring.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency		
DIRECT PLUME MONITORING					
	Fluid Sampling	M1, M2	Annually		
INDIRECT PLUME MONITORING					
	Pulse neutron logging	M1, M2	Every five years		

Table 5. Summary of analytical and field parameters for fluid sampling in the injection zone.

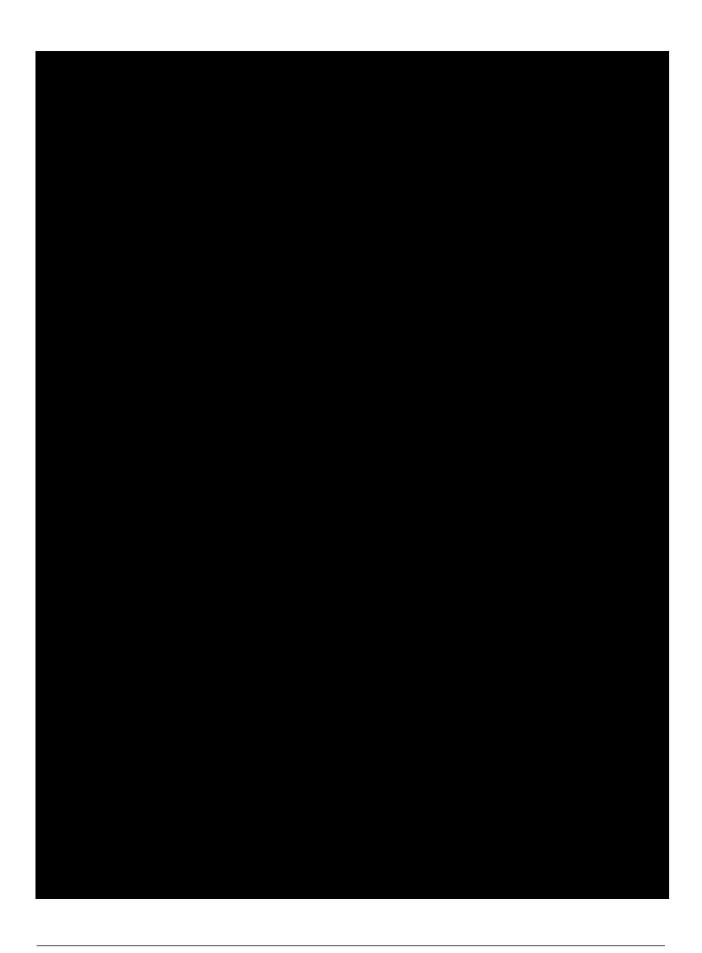
Parameters	Analytical Methods		
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Se, ZN, Tl)	ICP-MS EPA Method 6020		
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OES EPA Method 6010B		
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0		
Dissolved CO <sub>2</sub>	Coulometric titration ASTM D513-11		
δ13C	Isotope ratio mass spectrometry		
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)		
Oxygen, Argon and Hydrogen	ISBT 4.0 (GC/DID) GC/TCD		
Total Dissolved Solids	Gravimetry; Method 2540 C		
Alkalinity	Method 2320B		
pH (field)	EPA 150.1		
Specific Conductance (field)	SM 2510 B		
Temperature (field)	Thermocouple		

CTV will employ indirect and direct methods to monitor the pressure front (Table 6). Direct monitoring will include pressure gauges to monitor the pressure of the CO<sub>2</sub> plume in the three monitoring wells. Additionally, seismic monitoring via installed surface and/or shallow borehole seismometers well will be utilized to detect micro seismic events. Figures 3 and 4 show the location of the monitoring wells and the predicted extent of the CO<sub>2</sub> plume in plan view and cross-section.

Table 6. Post-injection phase pressure-front monitoring.

Target Formation	Monitoring Activity	Monitoring Location(s)	Frequency		
DIRECT PRESSURE-FRONT MONITORING					
	Pressure and temperature		Continuous		
INDIRECT PRESSURE-FRONT MONITORING					
All strata	Seismicity	AoR	Continuous		





## Schedule for Submitting Post-Injection Monitoring Results [40 CFR 146.93(a)(2)(iv)]

All post-injection site care monitoring data and monitoring results collected using the methods described above will be submitted to EPA in annual reports submitted within 90 days following the anniversary date on which injection ceases. The reports will contain information and data generated during the reporting period, i.e. well-based monitoring data, sample analysis, and the results from updated site models.

#### **Non-Endangerment Demonstration Criteria**

Prior to authorization of site closure, CTV will submit a demonstration of non-endangerment of USDWs to the Director as per 40 CFR 143.93(b)(2) or (3).

CTV will provide a report to the Director that demonstrated USDW non-endangerment based on the evaluation of site monitoring data. The report will detail how the non-endangerment determination is based on site-specific conditions, supported with the computational model. All relevant monitoring data and interpretations will be provided.

#### **Summary of Monitoring Data**

A summary of the site monitoring data, pursuant to the Testing and Monitoring Plan and this PISC and Site Closure Plan, including data collected during the injection and PISC phases of the project. Data submission will be in a format acceptable to the Director and will include:

- 1. A narrative that explains the monitoring activities,
- 2. Dates of all monitoring events,
- Changes to the monitoring program over time,
- 4. An explanation of all monitoring information that has existed at the site,
- 5. Explanation of how the monitoring data from injection and PISC has varied from the baseline data during site characterization, and
- 6. Summary of any emergencies that occurred during the injection and post-injection phases of the project. Included will be a description of how any issues have been resolved and that there is no endangerment to the USDW.

#### Evaluation of the CO<sub>2</sub> Plume and the AoR

Computational modeling results calibrated with monitoring data (e.g., pressure) will be used to support that the plume has stabilized and that the pressure change is negligible (less than 10 psi per year) and poses no risk for potential vertical migration. Computational modeling results calibrated with monitoring data from storage reservoir, USDW and above zone will be used to demonstrate:

- 1. the lack of CO<sub>2</sub> leakage over the project timeframe,
- 2. the accuracy of the model to predict and represent the storage reservoir, and
- 3. the computational model adequately defined the AoR.

#### **Evaluation of Reservoir Pressure**

Monitoring data will be reviewed to ensure that the CO<sub>2</sub> plume has stabilized post-injection and that the reservoir pressure change is negligible (less than 10 psi per year). This demonstration will be supported by the computational model that has been calibrated with the most recent monitoring data. The plume is trapped by structure and pinch-out of the reservoir sands. Plume migration is minimal, as such pressure stabilization will be used for non-endangerment assessment.

#### **Evaluation of Potential Conduits for Fluid Movement**

Wells that require corrective action will be reviewed and assessed prior to PISC and Site Closure, this includes monitoring wells, injection wells and other wells that penetrate within the AoR and the confining layer. Final demonstration will be made that natural and artificial conduits will not allow fluid migration from the storage reservoir.

#### **Evaluation of Seismicity Monitoring**

Demonstration will be made that the plume has stabilized and the pressure change is negligible (less than 10 psi per year), minimizing the risk for induced seismicity after site closure. Final review will be made with the seismicity monitoring to demonstrate seal integrity and that there is no further endangerment of to the USDW.

#### **Site Closure Plan**

CTV will conduct site closure activities to meet the requirements of 40 CFR 146.93(e), with notification to the permitting agencies at least 120 days prior to its intent to close the site. Upon approval of the permitting agencies, CTV will plug the injection and monitoring wells, restore the site and submit a site closure plan to the EPA.

A site closure report will be prepared and submitted within 90 days following site closure supported by the following:

- 1. Verification of injector and monitoring well plugging,
- 2. Notifications to state and local authorities as per 40 CFR 146.93 (f)(2),
- 3. Composition and volume of the injected CO<sub>2</sub>, and
- 4. Post-injection monitoring records

CTV will record a notation to the property's deed that will indicate:

- 1. The property was used for CO<sub>2</sub> sequestration, the period of injection and the volume of CO<sub>2</sub> injected,
- 2. The formation that the fluid was injected, and
- 3. The name of the local agency to which a plat of survey with injection well locations was submitted.

POST INJECTION SITE CARE AND SITE CLOSURE PLAN - FIGURES







# ATTACHMENT F: EMERGENCY AND REMEDIAL RESPONSE PLAN 40 CFR 146.94(a)

#### CTV III

#### **Facility Information**

Facility Name: CTV III

Facility Contact: William Chessum / Technical Manager

(562) 999-8380 / William.chessum@crc.com

Location:

This Emergency and Remedial Response Plan (ERRP) describes actions that Carbon TerraVault Holdings LLC (CTV) shall take to address movement of the injection fluid or formation fluid in a manner that may endanger an underground source of drinking water (USDW) during the construction, operation, or post-injection site care periods.

If CTV obtains evidence that the injected CO<sub>2</sub> stream and/or associated pressure front may cause an endangerment to a USDW, CTV must perform the following actions:

- 1. Initiate shutdown plan for the injection well.
- 2. Take all steps reasonably necessary to identify and characterize any release.
- 3. Notify the permitting agency (UIC Program Director) of the emergency event within 24 hours.
- 4. Implement applicable portions of the approved ERRP.

Where the phrase "initiate shutdown plan" is used, the following protocol will be employed: CTV will immediately cease injection. However, in some circumstances, CTV will, in consultation with the UIC Program Director, determine whether gradual cessation of injection (using the parameters set forth in Attachment A of the Class VI permit) is appropriate.

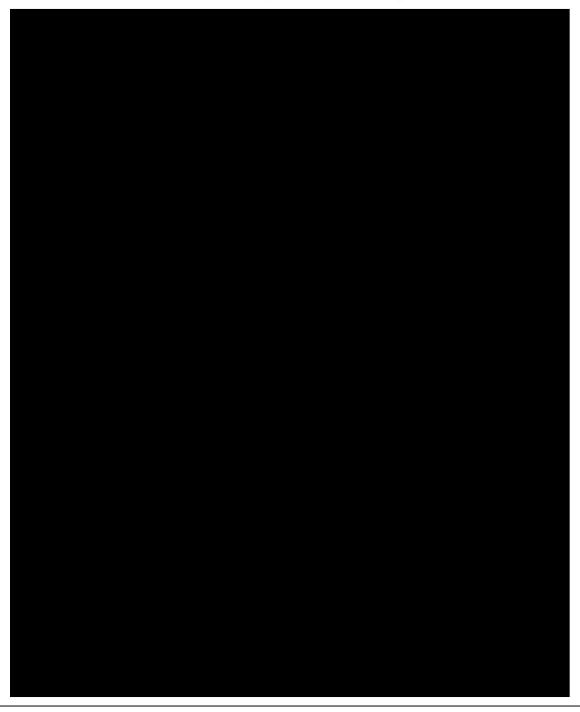
#### **Local Resources and Infrastructure**

Resources in the vicinity of the CTV facility that may be affected as a result of an emergency event at the project site include:

1. Base of Fresh water and USDW exist in project area at a measured depth of approximately 1100' and 2500' respectively.

- 2. Farming operations are present overlying AOR
- 3. The Nearest Town/Community from project is

Resources and infrastructure addressed in this plan are shown in Figure 1.



#### **Potential Risk Scenarios**

The following events related to the CTV facility that could potentially result in an emergency response:

- Well integrity failure
- Injection well or monitoring equipment failure (e.g., shut-off valve or pressure gauge, etc.);
- A natural disaster (e.g., earthquake, tornado, lightning strike, flooding);
- Potential Brine or CO<sub>2</sub> Leakage to a USDW;
- CO<sub>2</sub> leakage to USDW or land surface; or
- Induced or natural seismic event.

Response actions will depend on the severity of the event(s) triggering an emergency response. "Emergency events" are categorized as shown in Table 1.

Table 1. Degrees of risk for emergency events.

<b>Emergency Condition</b>	Definition
Major emergency	Event poses immediate substantial risk to human health, resources, or infrastructure. Emergency actions involving local authorities (evacuation or isolation of areas) should be initiated.
Serious emergency	Event poses potential serious (or significant) near term risk to human health, resources, or infrastructure if conditions worsen or no response actions taken.
Minor emergency	Event poses no immediate risk to human health, resources, or infrastructure.

#### **Emergency Identification and Response Actions**

Steps to identify and characterize the event will be dependent on the specific issue identified, and the severity of the event. The potential risk scenarios identified in Part 2 are detailed below.

#### Well Integrity Failure

Integrity loss at the injection well and/or verification well may endanger USDWs. Pursuant to 40 CFR 146.91(c)(3), CTV must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).

Integrity loss may have occurred if the following events occur:

- Automatic shutdown devices are activated:
  - Wellhead pressure exceeds the shutdown pressure specified in the permit.
  - Annulus pressure indicates a loss of external or internal well containment.

- Pursuant to 40 CFR 146.91(c)(3), CTV must notify the UIC Program Director within 24 hours of any triggering of a shut-off system (i.e., down-hole or at the service).
- Mechanical integrity test results identify a loss of mechanical integrity.

**Severity:** Low to moderate, dependent on the magnitude of the event.

Timing of event: Injection/monitoring

Avoidance measures: Well maintenance, monitoring and control of injection flow and pressure.

**Detection methods:** Mechanical integrity testing, unexpected injection wells pressure and rate changes, annulus pressure increase, and visual (CO<sub>2</sub> at surface).

#### Potential response actions:

- Notify the plant superintendent and project manager.
- Limit access to wellhead to authorized personnel only.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency (loss or increase of pressure or fluid volumes and/or loss of mechanical integrity during testing and maintenance):
  - Contact security to restrict access to the Storage site.
  - Initiate shutdown plan.
  - O Shut-in injection well and vent CO2 from surface facilities.
  - Communicate with CTV personnel and local authorities to initiate evacuation plans, as necessary.
  - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
  - o If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
  - If there is damage to the wellhead, repair the damage and conduct a survey to ensure that leakage has ceased.
  - Preform a well log/MIT to detect CO<sub>2</sub> movement outside of the casing.
  - Confirm well integrity prior to restarting injection (upon approval of the UIC Program Director).

- For a Minor emergency (downhole and surface sensor/monitoring equipment failure):
  - Conduct assessment to determine whether there has been a loss of mechanical integrity.
  - If there has been a loss of mechanical integrity, initiate shutdown plan.
  - Contact security to restrict access to the Storage site.
  - Initiate shutdown plan.
  - O Shut-in injection well and vent CO2 from surface facilities.
  - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
  - If contamination is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
  - o If there is damage to the wellhead, repair the damage and conduct a survey to ensure that leakage has ceased.
  - Preform a well log/MIT to detect CO<sub>2</sub> movement outside of the casing.
  - Confirm well integrity prior to restarting injection (upon approval of the UIC Program Director).

Response personnel: Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

#### Injection Well Monitoring Equipment Failure

The failure of monitoring equipment for wellhead pressure, temperature, and/or annulus pressure may indicate a problem with the injection well that could endanger USDWs.

Severity: Low

Timing of event: Injection

Avoidance measures: Well maintenance, and careful monitoring and control of injection flow and pressure.

Detection methods: Anomalies in monitoring data, and visual failure of equipment.

#### Potential response actions:

Notify the plant superintendent and project manager.

- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For a Major or Serious emergency (failure of sensors that will require shutdown of well to repair, requires extended repair time (>48 hours) and/or well intervention to remediate):
  - Contact security to restrict access to the Storage site.
  - Communicate with CTV personnel and local authorities to isolate the area and initiate evacuation plans, as necessary.
  - Initiate shutdown plan.
  - Shut-in injection well and vent CO<sub>2</sub> from surface facilities.
  - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
  - Identify and, if necessary, implement appropriate remedial actions (in consultation with the UIC Program Director).
  - Verify whether contamination has occurred via handheld CO2 monitors.
  - Confirm well integrity prior to restarting injection and upon approval of the UIC Program Director.
- For a Minor emergency (sensor or monitoring failure that does not require shutdown of the well to repair):
  - Conduct assessment to determine whether there has been a loss of mechanical integrity.
  - If there has been a loss of mechanical integrity, initiate shutdown plan and refer to Major or Serious emergency guidelines.
  - o Evaluate the cause of failure, and mitigate if necessary (i.e., repair equipment).
  - Contact security to restrict access to the Storage site.
  - Shut-in injection well and vent CO<sub>2</sub> from surface facilities.
  - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
  - Confirm well integrity prior to restarting injection and upon approval of the UIC Program Director.

**Response Personnel:** Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

Equipment: Drill rig, logging equipment, cement or casing and air and water testing equipment.

#### Potential Brine or CO<sub>2</sub> Leakage to USDW

Elevated concentrations of indicator parameter(s) in groundwater sample(s) or other evidence of fluid (brine) or  $CO_2$  leakage into a USDW.

Severity: Serious

Timing of event: Injection

**Avoidance measures**: CTV will operate the project to ensure containment of CO<sub>2</sub>. Contamination to USDWs will be avoided by:

- 1. Ensuring injection well integrity through well maintenance and mechanical integrity testing
- 2. Maintaining the injection pressure below the fracture gradient of the confining layer and assessing data from seismic monitoring to ensure competency of the confining layer.
- 3. Reviewing monitoring well data to understand plume extent.
- 4. Monitoring of the dissipation interval that overlies the confining layer to establish leakage before migration to USDW.

**Detection methods:** Pressure or water composition change in dissipation interval or USDW monitoring well.

#### Potential response actions:

- Notify the plant superintendent and project manager.
- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.
- For all emergencies (Major, Serious, or Minor):
  - Initiate shutdown plan.
  - Contact security to restrict access to the Storage site.
  - Shut-in injection well and vent CO<sub>2</sub> from surface facilities.
  - If the presence of indicator parameters is confirmed, develop (in consultation with the UIC Program Director) a case-specific work plan to:
    - Install additional groundwater monitoring points near the affected groundwater well(s) to delineate the extent of impact; and
    - Remediate unacceptable impacts to the affected USDW.

- Arrange for an alternate potable water supply, if the USDW was being utilized and has been caused to exceed drinking water standards.
- Proceed with efforts to remediate USDW to mitigate any unsafe conditions (e.g., install system to intercept/extract brine or CO<sub>2</sub> or "pump and treat" to aerate CO<sub>2</sub>-laden water).
- Continue groundwater remediation and monitoring on a frequent basis (frequency to be determined by CTV and the UIC Program Director) until unacceptable adverse USDW impact has been fully addressed.
- o If there is a well integrity issue refer to the Mechanical Integrity Failure scenario.
- If the leak poses a risk to air quality a perimeter will be established vi hand-held air monitoring devices.

**Response personnel:** Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

**Equipment:** Drill rig, logging equipment, groundwater remediation equipment, cement or casing and air and water testing equipment.

#### **Natural Disaster**

Well problems (integrity loss, leakage, or malfunction) may arise as a result of a natural disaster affecting the normal operation of the injection well. An earthquake may disturb surface and/or subsurface facilities; and weather-related disasters (e.g., tornado, flodding, or lightning strike) may affect surface facilities.

If a natural disaster occurs that affects normal operation of the injection well, CTV will perform the following:

**Severity:** Serious to catastrophic

**Timing of event:** Pre-injection, injection, and/or post injection phases.

**Avoidance measures**: N/A **Detection methods**: N/A

#### Potential response actions:

- Notify the UIC Program Director within 24 hours of the emergency event, per 40 CFR 146.91(c).
- Determine the severity of the event, based on the information available, within 24 hours of notification.

- For a Major or Serious emergency:
  - Initiate shutdown plan.
  - Contact security to restrict access to the Storage site.
  - Shut-in injection well and vent CO<sub>2</sub> from surface facilities.
  - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.
  - If there is contamination has occurred refer to the Potential Brine or CO<sub>2</sub>
     Leakage to USDW scenario.
  - Communicate with CTV personnel and local authorities to initiate evacuation procedures.
  - If there is a well integrity issue for the injector or monitoring well, refer to the Mechanical Integrity Failure scenario.
  - If contamination or endangerment is detected, identify, and implement appropriate remedial actions (in consultation with the UIC Program Director).
- For a Minor emergency:
  - Conduct assessment to determine whether there has been a loss of mechanical integrity.
  - If there has been a loss of mechanical integrity, initiate shutdown plan.
  - Contact security to restrict access to the Storage site.
  - Shut-in injection well and vent CO<sub>2</sub> from surface facilities.
  - Continuously monitor well pressure, temperature, and annulus pressure to assess integrity loss and determine the root cause of failure.

**Response personnel:** Emergency response personnel, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

**Equipment:** Drill rig, logging equipment, cement or casing and air and water testing equipment.

#### **Induced or Natural Seismic Event**

Based on the project operating conditions, it is highly unlikely that injection operations would ever induce a seismic event outside the AoR. Therefore, this portion of the response plan is developed for any seismic event with an epicenter within the AoR, inclusive of a two mile buffer.

To monitor the area for seismicity, CTV will install surface and shallow borehole seismometers to continuously record the site for seismic activity.

Severity: Major

Timing of event: Injection or post injection phases.

An induced seismic event will occur when the reservoir stresses are altered, which would occur during the injection phase.

Avoidance measures: N/A

**Detection methods:** The seismic monitoring network.

#### **Potential response Actions:**

Based on the periodic analysis of the monitoring data, observed level of seismic activity, and local reporting of felt events, the site will be assigned an operating state. The operating state is determined using threshold criteria which correspond to the site's potential risk and level of seismic activity. The operating state provides operating personnel information about the potential risk of further seismic activity and guides them through a series of response actions.

The seismic monitoring system structure is presented in Table 2. The table corresponds each level of operating state with the threshold conditions and operational response actions.

Table 2. Seismic monitoring system, for seismic events > M1.5 with an epicenter within a two-mile radius of the injection well.

Operating State	Threshold Condition <sup>1,2</sup>	Response Action <sup>3</sup>
Green	Seismic events less than or equal to M1.5	<ol> <li>Continue normal operation within permitted levels.</li> <li>Document the event in semiannual reports to the EPA.</li> </ol>
Yellow	Five (5) or more seismic events within a 30-day period having a magnitude greater than M1.5 but less than or equal to M2.0	<ol> <li>Continue normal operation within permitted levels.</li> <li>Initiate gradual shutdown of the well if it is determined appropriate.</li> <li>Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event.</li> <li>Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well.</li> <li>Document the event in semiannual reports to the EPA.</li> </ol>
Orange	Seismic event greater than M1.5 and local observation or felt report	<ol> <li>Continue normal operation within permitted levels.</li> <li>Initiate gradual shutdown of the well if it is determined appropriate.</li> </ol>
	Seismic event greater than M2.0 and no felt report	<ol> <li>Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event.</li> <li>Within 24 hours of the incident, notify the UIC Program Director of the operating status of the well.</li> <li>Report findings to the UIC Program Director and issue correctivity actions.</li> <li>Document the event in semiannual reports to the EPA</li> </ol>

<sup>&</sup>lt;sup>1</sup> Specified magnitudes refer to magnitudes determined by local Southern California Earthquake Data Center or USGS seismic monitoring stations or reported by the USGS National Earthquake Information Center using the national seismic network.

<sup>&</sup>lt;sup>2</sup> "Felt report" and "local observation and report" refer to events confirmed by local reports of felt ground motion or reported on the USGS "Did You Feel It?" reporting system.

<sup>&</sup>lt;sup>3</sup> Reporting findings to the UIC Program Director and issuing corrective action will occur within 25 business days (five weeks) of change in operating state.

Operating State	Threshold Condition <sup>1,2</sup>	Response Action <sup>3</sup>
Operating State  Magenta	Threshold Condition <sup>1,2</sup> Seismic event greater than M2.0 and local observation or report	<ol> <li>Initiate rate reduction plan.</li> <li>Vent CO<sub>2</sub> from surface facilities.</li> <li>Within 24 hours of the incident, notify the UIC Program Director, of the operating status of the well.</li> <li>Limit access to wellhead to authorized personnel only.</li> <li>Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary.</li> <li>Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director).</li> <li>Determine if leaks to ground water or surface water occurred.</li> <li>Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event.</li> <li>If USDW contamination is detected, endangerment and CO2 leaked:         <ul> <li>Notify the UIC Program Director within 24 hours of the</li> </ul> </li> </ol>
Red	Seismic event greater than M2.0, and local observation or report, and local report	<ul> <li>determination.</li> <li>b. Contact environmental and geotechnical professionals for expertise and advice.</li> <li>10. Assess monitoring plans and where necessary intensify the monitoring plan to ensure containment.</li> <li>11. Report findings to the UIC Program Director and issue corrective actions.</li> <li>12. Document the event in semiannual reports to the EPA.</li> <li>1. Initiate shutdown plan.</li> <li>2. Vent CO<sub>2</sub> from surface facilities.</li> <li>3. Within 24 hours of the incident, notify the UIC Program Director</li> </ul>
	and confirmation of damage <sup>4</sup>	of the operating status of the well.  4. Limit access to wellhead to authorized personnel only.

 $<sup>^4</sup>$  Onset of damage is defined as cosmetic damage to structures, such as bricks dislodged from chimneys and parapet walls, broken windows, and fallen objects from walls, shelves, and cabinets.

Operating State	Threshold Condition <sup>1,2</sup>	Response Action <sup>3</sup>
	Or Seismic event >M3.5	<ol> <li>Communicate with facility personnel and local authorities to initiate evacuation plans, as necessary.</li> </ol>
		6. Monitor well pressure, temperature, and annulus pressure to verify well status and determine the cause and extent of any failure; identify and implement appropriate remedial actions (in consultation with the UIC Program Director).
		7. Review seismic and operational data to determine location and magnitude of seismic event. If the event falls near the extents of the plume, estimate potential impacts to USDWs. Perform a pressure falloff test to determine if the storage complex has been compromised by the seismic event.
		8. Determine if leaks to ground water or surface water occurred.
		9. If USDW contamination is detected, endangerment and CO2 leaked:
		<ul> <li>a. Notify the UIC Program Director within 24 hours of the determination.</li> </ul>
		<ul> <li>b. Contact environmental and geotechnical professionals for expertise and advice.</li> </ul>
		10. Review seismic and operational data.
		11. Report findings to the UIC Program Director and issue corrective actions.
		12. Document the event in semiannual reports to the EPA.

**Response personnel:** Emergency response personnel, California Geological Survey, drilling crew, geotechnical professionals, and environmental or water treatment professionals.

**Equipment:** Depending on the operating state drill rig, logging equipment, cement or casing and air and water testing equipment.

#### **Response Personnel and Equipment**

Site personnel, project personnel, and local authorities will be relied upon to implement this ERRP.

Site personnel to be notified (not listed in order of notification):

1. Project Manager

Ken Haney (661-763-6101)

2. Field Manager

David Hauptman (661-858-3864)

3. Environmental Manager

Brian Pellens (661-321-6240)

4. Security and Emergency Response Director (24 hour contact)

Bill Blair (562-743-8336)

5. Public and Media Liaison

Joe Ashley (661-301-6551)

A site-specific emergency contact list will be developed and maintained during the life of the project. CTV will provide the current site-specific emergency contact list to the UIC Program Director.

Table 3. Contact information for key local, state, and other authorities.

Agency	Contact
San Joaquin County Sheriff	9-1-1 (Emergency) 209-468-4400 (Non-emergency)
California Governor's Office of Emergency Services (Cal OES)	(916) 845-8506
UIC Program Director (EPA)	Albright.David@epa.gov
EPA National Response Center (24 hours)	800-424-8802
California Geological Survey	(916) 322-1080
San Joaquin County Fire Department	9-1-1 (Emergency) 209-831-6700 (Non-emergency)
California Air Resources Board (CARB)	800-242-4450
Poison Control Center	800-342-9293
California Office of Emergency Services (24 hours)	800-852-7550
State Water Quality Control Board (Central Valley)	916-255-3000

Equipment needed in the event of an emergency and remedial response will vary, depending on the triggering emergency event. Response actions (cessation of injection, well shut-in, and evacuation) will generally not require specialized equipment to implement. Where specialized equipment (such as a drilling rig or logging equipment) is required, CTV shall be responsible for its procurement.

#### **Emergency Communications Plan**

CTV will communicate to the public about any event that requires an emergency response to ensure that the public understands what happened and whether or not there are any environmental or safety implications. The amount of information, timing, and communications method(s) will be appropriate to the event, its severity, whether any impacts to drinking water or other environmental resources occurred, any impacts to the surrounding community, and their awareness of the event.

CTV will describe what happened, any impacts to the environment or other local resources, how the event was investigated, what responses were taken, and the status of the response. For responses that occur over the long-term (e.g., ongoing cleanups), CTV will provide periodic updates on the progress of the response action(s).

CTV will also communicate with entities who may need to be informed about or take action in response to the event, including local water systems, CO<sub>2</sub> source(s) and pipeline operators, landowners, and Regional Response Teams (as part of the National Response Team).

#### Plan Review

This ERRP shall be reviewed:

- At least once every five (5) years following its approval by the permitting agency;
- Within one (1) year of an area of review (AOR) re-evaluation;
- Within 30 days, or other time prescribed by the EPA director, following any significant changes to the injection process or the injection facility, or an emergency event; or
- As required by the permitting agency.

If the review indicates that no amendments to the ERRP are necessary, CTV will provide the permitting agency with the documentation supporting the "no amendment necessary" determination.

If the review indicates that amendments to the ERRP are necessary, amendments shall be made and submitted to the permitting agency within three months following an event that initiates the ERRP review procedure.

#### **Staff Training and Exercise Procedures**

All CTV staff and contractors operating at the CO<sub>2</sub> sequestration facilities, or working in the AoR will be subjected to the following training either prior to deployment in the field or annually:

#### CO<sub>2</sub> Facilities Training

Onsite and classroom training for facility and infrastructure security, maintenance, and operations.

#### CO<sub>2</sub> Safety Training

**Carbon dioxide detection equipment:** Operation and maintenance of personal monitors, portable multi-gas monitors and stationary monitors throughout the facility.

**Carbon Dioxide Hazards:** Accidental exposure, adverse health effects, workplace exposure limits and first aid.

**Emergency Response:** Training in the event of CO<sub>2</sub> leakage and exercise and drills simulating potential emergency situations.

## Class VI Injection Well: Quality Assurance and Surveillance Plan

Update April 25, 2022

Prepared by:

Carbon TerraVault Holdings, LLC

## **Table of Contents**

Title and Approval Sheet	vi
Distribution List	vii
A. Project Management	1
A.1. Project/Task Organization	1
A.1.a/b. Key Individuals and Responsibilities	1
A.1.c. Independence from Project QA Manager and Data Gathering	1
A.1.d. QA Project Plan Responsibility	1
A.1.e. Organizational Chart for Key Project Personnel	1
A.2. Problem Definition/Background	2
A.2.a. Reasoning	2
A.2.b. Reasons for Initiating the Project	2
A.2.c. Regulatory Information, Applicable Criteria, Action Limits	2
A.3. Project/Task Description	2
A.3.a/b. Summary of Work to be Performed	
A.3.c. Geographic Locations	5
A.3.d. Resource and Time Constraints	5
A.4.Quality Objectives and Criteria	5
A.4.a. Performance/Measurement Criteria	
A.4.b. Precision	9
A.4.c. Bias	9
A.4.d. Representativeness	9
A.4.e. Completeness	9
A.4.f. Comparability	9
A.4.g. Method Sensitivity	10
A.5. Special Training/Certifications	11
A.5.a. Specialized Training and Certifications	11
A.5.b/c. Training Provider and Responsibility	12
A.6. Documentation and Records	12
A.6.a. Report Format and Package Information	12
A.6.b. Other Project Documents, Records, and Electronic Files	12
A.6.c/d. Data Storage and Duration	12
A.6.e. QASP Distribution Responsibility	12
B. Data Generation and Acquisition	12
B.1. Sampling Process Design	12
B.1.a. Design Strategy	12
Shallow Groundwater Monitoring Strategy	12
Deep Groundwater Monitoring Strategy	12
B.1.b. Type and Number of Samples/Test Runs	12
B.1.c. Site/Sampling Locations	13

B.1.d. Sampling Site Contingency	13
B.1.e. Activity Schedule	14
B.1.f. Critical/Informational Data	14
B.1.g. Sources of Variability	14
B.2. Sampling Methods	14
B.2.a/b. Sampling SOPs	14
B.2.c. In-situ Monitoring	15
B.2.d. Continuous Monitoring	15
B.2.e. Sample Homogenization, Composition, Filtration	15
B.2.f. Sample Containers and Volumes	15
B.2.g. Sample Preservation	15
B.2.h. Cleaning/Decontamination of Sampling Equipment	15
B.2.i. Support Facilities	15
B.2.j. Corrective Action, Personnel, and Documentation	15
B.3. Sample Handling and Custody	
B.3.a. Maximum Hold Time/Time Before Retrieval	15
B.3.b. Sample Transportation	16
B.3.c. Sampling Documentation	16
B.3.d. Sample Identification	16
B.3.e. Sample Chain-of-Custody	17
B.4. Analytical Methods	17
B.4.a. Analytical SOPs	
B.4.b. Equipment/Instrumentation Needed	
B.4.c. Method Performance Criteria	17
B.4.d. Analytical Failure	
B.4.e. Sample Disposal	
B.4.f. Laboratory Turnaround	
B.4.g. Method Validation for Nonstandard Methods	17
B.5. Quality Control	
B.5.a. QC activities	
B.5.b. Exceeding Control Limits	
B.5.c. Calculating Applicable QC Statistics	
Charge Balance	18
B.6. Instrument/Equipment Testing, Inspection, and Maintenance	18
B.7. Instrument/Equipment Calibration and Frequency	18
B.7.a. Calibration and Frequency of Calibration	18
B.7.b. Calibration Methodology	18
B.7.c. Calibration Resolution and Documentation	19
B.8. Inspection/Acceptance for Supplies and Consumables	19
B.8.a/b. Supplies, Consumables, and Responsibilities	19
B.9. Nondirect Measurements	19
B.9.a. Data Sources	19

B.9.b. Relevance to Project	19
B.9.c. Acceptance Criteria	19
B.9.d. Resources/Facilities Needed	19
B.9.e. Validity Limits and Operating Conditions	19
B.10. Data Management	
B.10.a. Data Management Scheme	
B.10.b. Recordkeeping and Tracking Practices	19
B.10.c. Data Handling Equipment/Procedures	20
B.10.d. Responsibility	20
B.10.e. Data Archival and Retrieval	
B.10.f. Hardware and Software Configurations	
B.10.g. Checklists and Forms	20
C. Assessment and Oversight	20
C.1. Assessments and Response Actions	
C.1.a. Activities to be Conducted	
C.1.b. Responsibility for Conducting Assessments	20
C.1.c. Assessment Reporting	20
C.1.d. Corrective Action	20
C.2. Reports to Management	
C.2.a/b. QA status Reports	20
D. Data Validation and Usability	21
D.1. Data Review, Verification, and Validation	21
D.1.a. Criteria for Accepting, Rejecting, or Qualifying Data	21
D.2. Verification and Validation Methods	
D.2.a. Data Verification and Validation Processes	
D.2.b. Data Verification and Validation Responsibility	
D.2.c. Issue Resolution Process and Responsibility	
D.2.d. Checklist, Forms, and Calculations	21
D.3. Reconciliation with User Requirements	
D.3.a. Evaluation of Data Uncertainty	
D.3.b. Data Limitations Reporting	21
References	22
Annondicos	22

## List of Tables

List of Tables	
Table 1. Summary of testing and monitoring.	3
Table 2. Monitoring Well Summary.	3
Table 3. Summary of analytical and field parameters for ground water samples.	5
Table 4. Summary of analytical and field parameters for CO2 Stream	6
Table 5. Summary of analytical parameters for corrosion coupons	7
Table 6. Summary of measurement parameters for field gauges.	7
Table 7. Actionable testing and monitoring outputs.	8
Table 8. Pressure and temperature—downhole quartz gauge specifications.	9
Table 9. Representative logging tool specifications for pulse neutron/RST and CBL logging.	9
Table 10. Pressure Field Gauge.	9
Table 11. Pressure Field Gauge — Injection Tubing Pressure.	10
Table 12. Pressure Field Gauge – Annulus Pressure.	10
Table 13. Temperature Field Gauge $-$ Injection Tubing Temperature.	10
Table 14. Mass Flow Rate Field Gauge – CO2 Mass Flow Rate	10
Table 15. Stabilization criteria of water quality parameters during shallow well purging.	13
Table 16. Summary of sample containers, preservation treatments, and holding times for	
CO2 gas stream analysis.	15
Table 17. Summary of sample containers, preservation treatments, and holding times for	
ground water samples.	15
ar a com	
List of Figures	
Figure 1: Organizational chart.	1
Figure 2: Monitoring well location map.	12

## **Title and Approval Sheet**

This Quality Assurance and Surveillance Plan (QASP) is approved for use and implementation at the Storage facility. The signatures below denote the approval of this document and intent to abide by the procedures outlined within it.

7Hurst	April 25, 2022
Signature	 Date
Travis Hurst	

## **Distribution List**

The following project participants will receive the completed Quality Assurance and Surveillance Plan (QASP) and all future updates for the duration of the project.

Travis Hurst: CCS Project Manager

Carbon TerraVault 28590 Highway 119 Tupman, CA 93276

#### A. Project Management

## A.1. Project/Task Organization

#### A.1.a/b. Key Individuals and Responsibilities

The Storage project, led by Carbon TerraVault Holdings LLC (CTV), includes participation from service providers. The responsibilities for Testing and Monitoring will be shared between CTV and the service providers.

CTV will be responsible for any data and submissions made to the EPA.

#### A.1.c. Independence from Project QA Manager and Data Gathering

CTV utilizes a third-party service provider to collect, transport and analyze samples as part of the Testing and Monitoring Plan.

#### A.1.d. QA Project Plan Responsibility

CTV will be responsible for the Quality Assurance and Surveillance Plan. CTV will review the plan with service providers periodically.

#### A.1.e. Organizational Chart for Key Project Personnel

Figure 1 shows the organizational structure for the project. Although these roles have not been filled because the project is not operational, the chart shows the breakdown in responsibilities for future positions.

Project
Manager

Environmental
Manager

Technical
Manager
Manager

Reporting
Manager

Figure 1: Organizational Chart.

#### A.2. Problem Definition/Background

#### A.2.a. Reasoning

The project will inject and sequester CO<sub>2</sub> from industrial sources. The project requires a comprehensive monitoring plan that gathers data to assess confinement of the CO<sub>2</sub> injectate. To ensure accurate measurement and reporting this QASP outlines detail associated with the surveillance related to sampling, operating, and recording.

#### A.2.b. Reasons for Initiating the Project

CTV initiated the project for ESG purposes and to reduce carbon footprint for CTV operations and for external emissions. The project area has available pore space and confinement.

#### A.2.c. Regulatory Information, Applicable Criteria, Action Limits

CO<sub>2</sub> injection as per standard operating procedures and regulations requires that the injectate isconfined in the reservoir and that groundwater is not impacted. As such the following monitoring is necessary:

- 1. Injection well mechanical integrity testing
- 2. Injection well testing and operating data collection
- 3. Groundwater monitoring
- 4. Validation of the CO2 plume areal coverage as defined by numerical modeling

The information and data below define the steps to ensure that monitoring data quality provides the confidence and information to verify confinement.

#### A.3. Project/Task Description

#### A.3.a/b. Summary of Work to be Performed

Table 1. Summary of Testing and Monitoring.

Activity	Location(s)	Method	Analytical Technique	Lab/Custody	Purpose
Injection well					
Carbon dioxide stream analysis	Compressor	Direct Sampling	Chemical Analys is	Eurofins	Monitor Injectate
Injection rate and volume	Injection Well (s)	Flow meter	Direct Measurement	NA	Monitor rate and volume
Injection pressure	Injection weIlhead(s)	Pressure gauge	Direct Measurement	NA	Monitor injection pressure
Annular pressure	Injection Wellhead(s)	Pressure gauge	Direct Measurement	NA	Monitor annular pressure
Temperature	Along Wellbore(s)	DTS	Direct Measurement	NA	Monitor temperature
Downhole pressure/ temperature	Injection Well(s)	Downhole gauge	Direct Measurement	NA	Monitor reservoir pressure and temperature
Corrosion monitoring	Between compressor and wellhead	Corrosion Coupon	NA	Eurofins	Monitor corrosion of materials
Mechanical integrity	Injection Well(s)	Temperature		NA	Wellbore Integrity
Pressure Fall Off Test	Injection Well(s)	Pressure gauge	Pressure Transient Analysis	NA	Reservoir Assessment

Table 2. Monitoring Well Summary

A set in ite	Location(c)	Machael	Analytical Toolanian	Lob /Custody	Green
ACLIVITY	rocarron(s)	BOIDBIA	Allany ucal requillque	Lab/Custouy	acod in a
Monitoring Wells Above Confining Layer	iing Layer				
Fluid Sampling (USDW)	USDW Monitoring Well	Direct Sampling	Chemical Analysis	Eurofins	Monitor water quality
Pressure/Temperature (USDW)	USDW Monitoring Well	Gauge	Direct Measurement	NA	Monitor pressure / temperature
Pressure/Temperature Dissipation layer	Dissipation layer monitoring well	Gauge	Direct Measurement	NA	Monitor pressure/Temperature
Temperature Dissipation layer	Dissipation layer monitoring well	DTS	Direct Measurement	NA	Monitor Temperature
Fluid Sampling Dissipation layer	Dissipation layer monitoring well	Direct Sampling	Chemical Analysis	Eurofins	Monitor water quality
Storage Reservoir					
Pressure/Temperature	Monitor well (s)	Downhole gauge	Direct Measurement	NA	Monitor reservoir pressure/temperature
Temperature	Monitor well (s)	DTS	Direct Measurement	NA	Temperature
Fluid Sampling	Monitor well (s)	Direct Sampling	Chemical Analysis	Eurofins	Monitor water quality
Pulse Neutron Log	Monitor well (s)	Logging	Logging	NA	Saturation

## A.3.c. Geographic Locations

## A.3.d. Resource and Time Constraints

CTV has obtained surface access for the duration of the project.

## A.4. Quality Objectives and Criteria

## A.4.a. Performance/Measurement Criteria

Table 3. Summary of Analytical and Field Parameters for Fluid Samples.

Parameters	Analytical Methods <sup>(1)</sup>	Detection Limit/Range	<b>Typical Precisions</b>	QC Requirements
Cations (Al, Ba, Mn, As, Cd, Cr, Cu, Pb, SB, Se, Zn, Ti)	ICP-MS EPA Method 6020	0.05 to 5 mg/L	15%	Daily calibration of equipment/CCV/ Blank LCS, MS/MSD/ QC/ICV
Cations (Ca, Fe, K, Mg, Na, Si)	ICP-OES EPA Method 6010B	0.1 to 2 mg/L	15%	Daily calibration/CCV/ Blank LCS, MS/MSD/ QC/ICV
Anions (Br, Cl, F, NO3, SO4)	Ion Chromatography, EPA Method 300.0	0.02-0.13 mg/L	15%	Daily calibration/CCV/ Blank LCS, MS/MSD/ QC/ICV
Dissolved CO <sub>2</sub>	Coulometric titration ASTM D513-11	10 mg/L	NA	Duplicate analysis
Total dissolved solids	Gravimetrγ; Method 2540 C	10 mg/L	10%	Daily balance calibration, duplicates, blanks
Alkalinity	Method 2320B	10 mg/L	10%	Duplicate analysis
pH (field)	EPA 150.1	2 to 12.5pH	0.2 pH	Daily calibration, duplicates
Specific conductance (field)	SM 2510 B	10 ohms/cm	1%	Daily calibration, duplicates
Temperature (field)	Thermocouple	-5 to 50 C	0.2 C	Monthly calibration
613C	Isotope ratio mass spectrometry	12.2 mg/L HCO <sub>3</sub>	0.15%	Duplicate analysis
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)	1 mg/l	5-10% of reading	Daily calibration, duplicates

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

Table 4. Summary of Analytical Parameters for CO<sub>2</sub> Stream.

Parameters	Analytical Methods <sup>(1)</sup>	Detection Limit/Range	Typical Precisions	QC Requirements
Oxygen	ISBT 4.0 (GC/DID)	50 ppmv	15%	Daily calibration/CCV, blank, QC sample
Nitrogen	ISBT 4.0 (GC/DID)	50 ppmv	15%	Daily calibration/CCV, blank, QC sample
Carbon monoxide	ISBT 5.0 (Colorimetric) ISBT 4.0 (GC/DID)	50 ppmv	15%	Daily calibration/CCV, blank, QC sample
Total hydrocarbons	ISBT 10.0 THA (FID)	10 ppmv	15%	Daily calibration/CCV, blank, QC sample
Methane	ISBT 10.1 (FID)	10 ppmv	15%	Daily calibration/CCV, blank, QC sample
Hydrogen sulfide	ISBT 14.0 (GC/SCD)	10 ppmv/1 ppmv	15%	Daily calibration/CCV, blank, QC sample
Ethanol	ISBT 11.0 (GC/FID)	0.5 ppmv	20%	Daily calibration/CCV, blank, LCS, MS/MSD, ICV
CO <sub>2</sub> purity	ISBT 2.0	50 ppmv	15%	Daily calibration/CCV, blank, QC sample
Total Sulfur	ISBT 14.0 (GC/SCD)	1 ppmv	15%	Daily calibration/CCV, blank, QC sample

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

Table 5. Summary of Analytical Parameters for Corrosion Coupons.

Parameters	Analytical Methods	Detection Limit/Range	Typical Precisions	QC Requirements
Mass	NACE TM0169/ G31 EPA 1110A SW846	0.001 mg	10%	Duplicate analysis

Table 6. Summary of Measurement Parameters for Field Gauges.

Parameters	Methods	Detection Limit/Range	Typical Precisions	<b>QC Requirements</b>
Booster pump discharge pressure	ANSI 2540-1-1994	0.001 / 0 - 5,000 PSI	0.01 PSI	Annual calibration
Injection tubing temperature	ANSI Z540-1-1994	0.001 Fahrenheit / 0 – 500 Fahrenheit	0.01 Fahrenheit	Annual calibration
Injection tubing pressure	ANSI Z540-1-1994	0.001 / 0 - 5,000 PSI	0.01 PSI	Annual calibration
Annulus pressure	ANSI 2540-1-1994	0.001 / 0 - 5,000 PSI	0.01 PSI	Annual calibration
Injection mass flow rate	NA	0.1 % of flow rate	0.01 lbs/hour	Annual calibration

Table 7. Actionable Testing and Monitoring Outputs.

Activity or Parameter	Project Action Limit	Detection Limit	Anticipated Reading
External and internal mechanical integrity (temperature log)	Temperature log indicates a mechanical integrity issue.	0.01 Fahrenheit	Results will be compared to baseline. Deviation may be indicative of mechanical issue.
Surface and downhole pressure	Action will be taken when pressure is outside of expected or modeled range.	0.001 PSI	No greater than the maximum operating pressure.
Water quality (USDW)	Action will be taken when water sample is outside of baseline analysis.	0.2 pH	CO <sub>2</sub> will decrease the water pH.
Above-confining-zone pressure	Action will be taken if the pressure of the confining zone pressure increases.	0.001 PSI as per installed pressure gauge.	Reservoir pressure.

#### A.4.b. Precision

Field blanks will be collected once per sampling event to assess water sampling analysis accuracy. Service provider will be responsible for analytical precision as per their standard operating procedures.

#### A.4.c. Bias

Laboratory analysis bias will be assessed and addressed by the individual service provider as per their procedures and methodology.

There is no bias for direct pressure, temperature, and logging measurements.

#### A.4.d. Representativeness

CTV designed the monitoring network to ensure that samples acquired were representative of site conditions. Standard operating procedures during acquisition at the wellsite will ensure that samples are representative of the formation.

#### A.4.e. Completeness

Data completeness (amount of data obtained versus the expected data) of 90% for ground water sampling will be acceptable.

Direct measurements, such as pressure and temperature data, will be recorded 90% of the time.

#### A.4.f. Comparability

Data sets will always be compared to the baseline and previous analysis. Individual threshold changes will be assessed as well as small trend changes.

## A.4.g. Method Sensitivity

The following tables provide detail on gauge sensitivities.

Table 8. Pressure and Temperature—Downhole Gauge Specifications.

Parameter	Value
Calibrated working pressure range	0 – 10,000 PSI
Initial pressure accuracy	< 2 PSI
Pressure resolution	0.005 PSI
Pressure drift stability	< 1 PSI per year
Calibrated working temperature range	77 – 266 degrees Fahrenheit
Initial temperature accuracy	< 0.9 Fahrenheit
Temperature resolution	0.009 Fahrenheit
Temperature drift stability	0.1 degrees Fahrenheit per year
Max temperature	302 degrees Fahrenheit
Instrument calibration frequency	Annual

Table 9. Representative Logging Tool Specifications.

Parameter	RST (Pulse Neutron)	CBL
Logging speed	200 feet/hour	1,800 feet/hour
Vertical resolution	15 inches	6 inches
Investigation	Mechanical integrity	Cement bond with casing and formation
Temperature rating	302 Fahrenheit	350 Fahrenheit
Pressure rating	15,000 PSI	20,000 PSI

Table 10. Pressure Field Gauge.

Parameter	Value
Calibrated working pressure range	0 to 3,000 PSI
Initial pressure accuracy	< 0.04365 %
Pressure resolution	0.001 PSI
Pressure drift stability	0.125% of upper range limit for 60 months

Table 11. Pressure Field Gauge—Injection Tubing Pressure.

Parameter	Value
Calibrated working pressure range	0 – 3,000 PSI and 4-20 mA
Initial pressure accuracy	<0.03125%
Pressure resolution	0.001 PSI and 0.00001 mA
Pressure drift stability	0.125% of upper range limit for 60 months

#### Table 12. Pressure Field Gauge—Annulus Pressure.

Parameter	Value
Calibrated working pressure range	0 to 3,000 PSI
Initial pressure accuracy	< 0.025 %
Pressure resolution	0.001 PSI
Pressure drift stability	0.125% of upper range limit for 60 months

#### Table 13. Temperature Field Gauge—Injection Tubing Temperature.

Parameter	Value
Calibrated working temperature range	0 to 500 degrees Fahrenheit and 4-20ma
Initial temperature accuracy	<0.0055%
Temperature resolution	0.001 degrees Fahrenheit and 0.0001 mA
Temperature drift stability	0.15% of output reading or 0.15 degrees Celsius

### Table 14. Mass Flow Rate Field Gauge—CO<sub>2</sub> Mass Flow Rate.

Parameter	Value
Calibrated working flow rate range	0 to 3,000 PSI
Initial mass flow rate accuracy	0.1 % of upper range limit
Mass flow rate resolution	0.1 PSI
Mass flow rate drift stability	Estimate < 0.3% of output reading for 12 months

#### A.5. Special Training/Certifications

#### A.5.a. Specialized Training and Certifications

CTV will utilize lab and logging companies to acquire field data samples. All equipment will be provided and operated by the service provider.

#### A.5.b/c. Training Provider and Responsibility

Training will be provided and assessed by the individual service providers.

#### A.6. Documentation and Records

#### A.6.a. Report Format and Package Information

CTV will prepare and submit semi-annual reports to the EPA. The reports will include all testing, data, and monitoring information as specified in the Testing and Monitoring Plan.

#### A.6.b. Other Project Documents, Records, and Electronic Files

CTV will prepare and provide all necessary documents, records or electronic files as required.

#### A.6.c/d. Data Storage and Duration

CTV will maintain the required project data collected in a datastore.

#### A.6.e. QASP Distribution Responsibility

The project manager will be responsible for ensuring that those on the distribution list, and other essential staff, receive the most current copy of the QASP.

### B. Data Generation and Acquisition

#### **B.1. Sampling Process Design**

#### B.1.a. Design Strategy

Shallow Groundwater Monitoring Strategy

USDW Groundwater Monitoring Strategy

A groundwater monitoring well will assess potential changes in the lowermost USDW within the undifferentiated nonmarine sediments. Although the proposed monitoring zone is a USDW based on having groundwater less than 10,000 ppm TDS, the water supply wells in the AoR are completed above the base of fresh water. Monitoring of the lowermost USDW is more protective than monitoring the fresh water aquifers because impacts would occur in the lowermost USDW before the fresh water aquifers. The monitoring wells are located near potential conduits.

CTV will also monitor pressure changes associated with the storage project and fluid analysis.

Between the	A laterally
continuous	will be pressure monitored for potential CO2 leakage. The sands have
adequate continuity, porc	sity and permeability to ensure that the AoR is monitored.
Any unlikely leakage from	the storage reservoir up through
in the	

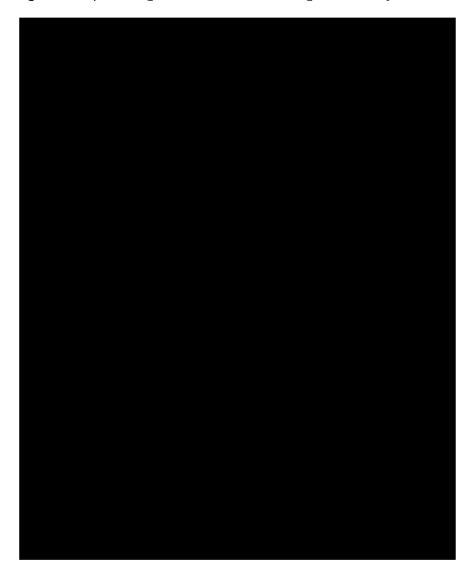
## B.1.b. Type and Number of Samples/Test Runs

The sampling activities are summarized in Table 1.

## B.1.c. Site/Sampling Locations

Locations for sampling are shown on he map below (Figure 2).

Figure 2: Map showing the location of monitoring wells and injection wells.



#### B.1.d. Sampling Site Contingency

CTV has obtained surface access for the duration of the project.

#### B.1.e. Activity Schedule

The sampling activities are summarized in Table 1.

#### B.1.f. Critical/Informational Data

Documentation of information will include the following:

- 1. Sampling metadata that includes sample label, purging time and other sample collection procedures.
- 2. Data collected in the field (temperature and pH).
- 3. Chain of custody.
- 4. Data and analysis collected in the laboratory.
- 5. Calibration of Instrumentation and equipment.

#### B.1.g. Sources of Variability

Potential sources of variability include the following:

- Natural and operational variability in fluid quality, temperature, and pressure.
- 2. Reservoir changes from outside the AoR (outside operator, precipitation/drought)
- 3. Changes in the sampling methods, service provider and instrumentation.

Variability will be minimized by the following:

- 1. Adhering to standard operating procedures.
- 2. Assessing data and results against baseline and previous results for trend and changes.
- 3. Service provider staff training.
- 4. Assessing calibration and calibrating procedures.
- 5. Quality control checks for samples.

#### **B.2. Sampling Methods**

#### B.2.a/b. Sampling SOPs

Refer to the table below for stabilization criteria during well purging.

Laboratory SOPs have been developed by the service provider.

All procedures for sampling shall be consistent with the U.S. Environmental Protection Agency (US EPA) Groundwater Sampling Guidelines for Superfund and RCEAA Project Mangers (May 2002).

Table 15. Stabilization Criteria of Water Quality Parameters During Well Purging.

Field Parameter	Stabilization Criteria
рН	+/- 0.01
Temperature	+/- 1 C
Specific conductance	+/- 3%

#### B.2.c. In-situ Monitoring

In-situ monitoring of water chemistry is not currently planned.

#### **B.2.d.** Continuous Monitoring

Pressure will be collected from monitoring wells.

#### B.2.e. Sample Homogenization, Composition, Filtration

To obtain a representative sample, each well will be purged at a flow rate between 10 GPM and 5- GPM. Samples will be collected within 24 hours of the well being purged. If a monitoring well will not supply adequate water for sampling, the condition of the well will be investigated and may be considered for replacement.

Purging will continue until three successive measurements of the indicator parameters meet the stabilization criteria per Table 15.

#### **B.2.f. Sample Containers and Volumes**

Sample collection devices will be carefully chosen to minimize the potential for altering the quality of the sample. Teflon and stainless steel are preferred materials, although PVC, HDPE and other similar materials are considered sufficient in some cases.

Refer to the tables below as needed for sample container, preservation, and holding time information.

#### B.2.g. Sample Preservation

Samples will be preserved as per Table 17.

#### B.2.h. Cleaning/Decontamination of Sampling Equipment

Equipment used for sampling and other activities associated with on-site work will be de-contaminated before and after performance of a given activity. Disposable items will be disposed of as solid waste in an approved, permitted client facility.

#### **B.2.i. Support Facilities**

Support facilities will be provided by the service provider responsible for sampling and analysis.

#### B.2.j. Corrective Action, Personnel, and Documentation

The service provider will be responsible for testing instruments and equipment and performing corrective action on defective equipment. Corrective action taken on equipment will be documented.

#### B.3. Sample Handling and Custody

#### B.3.a. Maximum Hold Time/Time Before Retrieval

See Table 16 and 17 for holding times.

#### B.3.b. Sample Transportation

CTV will ensure that samples are delivered to the laboratory for analysis by the service provider as soon as possible following sample collection. Samples will be transported to the laboratory on the same day as the sample collection.

During transportation, precautions will be implemented to ensure that sample integrity is not affected by extreme temperatures and/or excessive vibration.

Upon arrival at the service provider the samples will be reviewed to ensure the following:

- 1. The sample arrived intact without container leakage or breakage.
- 2. Chain of custody documentation and sample labels agree
- 3. Confirmation that the sample was preserved correctly.

#### B.3.c. Sampling Documentation

For each test in the field, a worksheet will be compiled for each test interval documenting the procedures and results.

#### B.3.d. Sample Identification

Samples will be identified with the well location, date sample identification, sampler, and sample type.

Table 16. Summary of Sample Containers, Preservation Treatments, and Holding Times for CO<sub>2</sub> Gas Stream Analysis.

Sample	Volume/Container Material	Preservation Technique	Sample Holding time (max)
CO <sub>2</sub> gas stream	One-liter tedlar bag	None	72 hours

Table 17. Summary of Anticipated Sample Containers, Preservation Treatments, and Holding Times for Ground Water Samples.

Target Parameters	Volume/Container Material	Preservation Technique	Sample Holding Time
Cations: Ca, Fe, Mg, K, Na, Si, Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb, Se, Ti	100 mL plastic	0-6ºC, Nitric acid	180 days
Anions: Br, Cl, F, NO₃ and SO₄	100 mL plastic	0-6ºC, None	48 hours
Dissolved CO <sub>2</sub>	100 ml plastic	0-6ºC, None	14 days
Isotopes: Carbon isotope 13	100 ml plastic	0-6ºC, None	14 days
Alkalinity	100 mL plastic	0-6ºC, None	14 days

#### B.3.e. Sample Chain-of-Custody

Sample transport and handling will be strictly controlled by the service provider field technician to reduce the opportunity for tampered samples. Upon delivery to the laboratory samples will be given unique laboratory sample numbers and recorded in a logbook indicating the client, well number, date, and time of delivery.

#### **B.4. Analytical Methods**

#### B.4.a. Analytical SOPs

All procedures to sample and analyze groundwater will be consistent with the U.S. Environmental Protection Agency Groundwater Sampling Guidelines for Superfund and RCRA Project Managers (May 2002).

#### B.4.b. Equipment/Instrumentation Needed

Service providers are expected to provide and utilize the equipment and instruments necessary to perform the required testing and analysis.

Examples of equipment and instrumentation includes safety equipment, sample jars, decontamination supplies, pH meter, EC meters, temperature gauges, and materials to document chain of custody, results, and labels.

#### B.4.c. Method Performance Criteria

All analytical methods employed by CTV at the storage project are industry standard and well define. Method performance criteria is not necessary.

#### B.4.d. Analytical Failure

Service providers conducting analysis are responsible for assessing and addressing analytical failure per their internal procedures and standards.

#### B.4.e. Sample Disposal

Service providers conducting analysis are responsible for proper sample disposal per internal procedures and standards.

#### B.4.f. Laboratory Turnaround

Laboratory turnaround times will vary by the analysis being conducted. CTV will communicate to service providers that a 30-day turnaround time for most analysis' is expected.

#### B.4.g. Method Validation for Nonstandard Methods

All analytical methods employed by CTV at the Storage project are industry standard and well defined. Method performance criteria is not necessary.

#### **B.5. Quality Control**

#### B.5.a. QC activities

Field quality control may involve the collection of two types of QC blanks, trip, and field blanks, to verify that the sample collection and handling processes have not impaired quality of the final samples.

Trip blank – Trip blanks are prepared for VOC analysis and transported with the empty sample container.

Field Blank- the field blank will be taken in the field to evaluate if certain sampling or cleaning procedures result in cross-contamination of site samples or if atmospheric contamination has occurred.

#### B.5.b. Exceeding Control Limits

In the case that control limits are exceeded, CTV will review the sampling procedures and results. In the case of a valid test, refer to the Emergency Response Plan for water contamination procedures.

#### B.5.c. Calculating Applicable QC Statistics

Charge Balance - Solutions must be electrically neutral, the total sum of all the positive charges (cations) must equal the total sum of all negative charges (anions).

Charge Balance: 
$$\sum cations = \sum anions$$

Charge balance error (shown below) will be less than ±5% for acceptable water analyses.

$$CBE = \frac{\sum cations - |\sum anions|}{\sum cations + |\sum anions|} \times 100$$

#### B.6. Instrument/Equipment Testing, Inspection, and Maintenance

The service provider will test, inspect, and maintain the instrumentation and equipment used for testing, this will be completed as per the manufacturer's guidelines and the standard operating procedures.

#### B.7. Instrument/Equipment Calibration and Frequency

#### B.7.a. Calibration and Frequency of Calibration

Pressure and temperature gauges will be calibrated according to the manufacturer's recommendations. Calibration certificates will be kept on file.

Lab instrumentation and calibration will be checked weekly to ensure that results are within the control range of parameters.

#### B.7.b. Calibration Methodology

Instruments will be calibrated for accurate readings. Calibrations will be conducted with individual instrument SOP's and in accordance with the manufacturer's supplied manual for each instrument.

#### B.7.c. Calibration Resolution and Documentation

Instrument calibration resolution will be consistent with the manufacturer's recommendations. Documentation for instrument calibration will be maintained in a database.

#### B.8. Inspection/Acceptance for Supplies and Consumables

#### B.8.a/b. Supplies, Consumables, and Responsibilities

The service provider responsible for completing sample collection and analysis will be responsible for supplies and consumables.

Supplies and consumables used for sample collection and analysis will be selected to minimize the potential for altering the quality of the sample and analysis results.

#### **B.9. Nondirect Measurements**

#### B.9.a. Data Sources

Induced seismicity will be monitored continuously to ensure data consistency. CTV will partner with or use a third party to process the data.

#### B.9.b. Relevance to Project

Passive seismic monitoring will be used to assess induced seismicity events as an indicator of stress changes in the subsurface. Thresholds and response for induced seismic events are discussed further in the Emergency Response Plan.

#### B.9.c. Acceptance Criteria

Industry standard practices will be utilized for data gathering, processing and interpretation.

#### B.9.d. Resources/Facilities Needed

CTV will use a service provider for all necessary resources and facilities for passive seismic monitoring.

#### B.9.e. Validity Limits and Operating Conditions

CTV and service provider professionals will ensure that all results and processes are conducted as per standard industry practices.

#### **B.10. Data Management**

#### B.10.a. Data Management Scheme

CTV will maintain the storage project data internally. Data will be backed up and held on secure servers.

#### B.10.b. Recordkeeping and Tracking Practices

All data associated with the project will be held securely and associated meta-data will be gathered and maintained to ensure tracking purposes.

#### B.10.c. Data Handling Equipment/Procedures

CTV employs robust data management procedures to ensure security of data gathered from the field and external data sources.

#### B.10.d. Responsibility

Project managers will be responsible for ensuring data management is properly maintained.

#### B.10.e. Data Archival and Retrieval

CTV will hold all data associated with the Storage project. A data store will be developed for reporting and retrieval.

#### B.10.f. Hardware and Software Configurations

CTV will ensure that software and hardware are appropriate to integrate the multiple data sources and maintain large quantities of data.

#### B.10.g. Checklists and Forms

CTV will generate forms, checklists, and procedures as necessary to ensure management, security and quality of all data collected.

### C. Assessment and Oversight

#### C.1. Assessments and Response Actions

#### C.1.a. Activities to be Conducted

Monitoring results will be obtained as per Table 1. Results will be reviewed for QC criteria as per section B.5. In the case of data failure, new samples will be collected and analyzed. Evaluation for data consistency will be performed per the USEPA 2009 Unified Guidance (USEPA, 2009).

#### C.1.b. Responsibility for Conducting Assessments

CTV will utilize service providers to analyze sample data. These organizations will be responsible for conducting their own internal assessments.

#### C.1.c. Assessment Reporting

Assessment information will be reported to the project leads as outlined in A.1.

#### C.1.d. Corrective Action

Corrective action issues, data collection, and monitoring data will all be handled by CTV.

#### C.2. Reports to Management

#### C.2.a/b. QA status Reports

CTV will notify the EPA and project leaders of QA report status if there are changes to the Testing and Monitoring Plan or the QASP.

### D. Data Validation and Usability

#### D.1. Data Review, Verification, and Validation

#### D.1.a. Criteria for Accepting, Rejecting, or Qualifying Data

Data validation will include the review of the results, chain of custody information, and review of the blank and duplicate information. All results will be stored in a database and compared to baseline and previous results. Data will be graphed to inspect trends and anomalies.

#### D.2. Verification and Validation Methods

#### D.2.a. Data Verification and Validation Processes

Datawill be verified by CTV upon receipt of results.

If anomalous datais suspected, CTV and the service provider will review the metadata associated with the sample to assess whether sampling, collection and the analysis conducted caused spurious results. In addition, instrument calibration will be reviewed if necessary.

#### D.2.b. Data Verification and Validation Responsibility

Data will be verified by CTV upon receipt of results.

#### D.2.c. Issue Resolution Process and Responsibility

CTV will oversee sample handling and assessment process. CTV management will determine actions necessary to resolve issues.

#### D.2.d. Checklist, Forms, and Calculations

CTV will develop checklists and a GIS database to store data, complete surveillance and ensure that permit requirements are met.

#### D.3. Reconciliation with User Requirements

#### D.3.a. Evaluation of Data Uncertainty

CTV will develop a GIS database that will be used for surveillance. The database will ensure data quality using methods consistent with USEPA 2009 Unified Guidance.

#### D.3.b. Data Limitations Reporting

Service provider management will be responsible for ensuring that analysis in their laboratory is presented with data use limitations for reporting.

Project leaders and managers will be responsible for ensuring that results are vetted and evaluated to determine if performance criteria are met.

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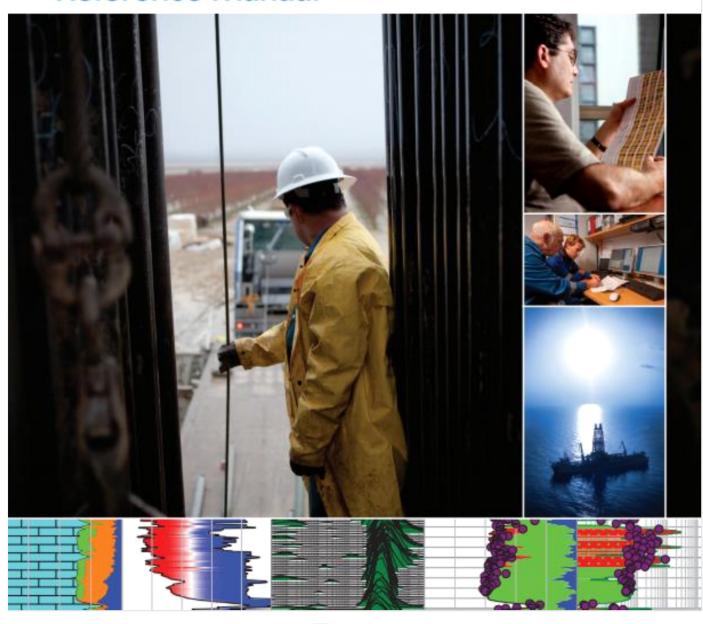
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#### **Appendices**

Schlumberger Wireline Log Quality Reference Manual

# Schlumberger

# Wireline Log Quality Control Reference Manual



## Schlumberger

### RST and RSTPro

#### Overview 0

The dual-detector spectrometry system of the through-tubing RST\* and RSTPro\* reservoir saturation tools enables the recording of carbon and oxygen and Dual-Burst\* thermal decay time measurements during the same trip in the well.

The carbon/oxygen (C/O) ratio is used to determine the formation oil saturation independent of the formation water salinity. This calculation is particularly helpful if the water salinity is low or unknown. If the salinity of the formation water is high, the Dual-Burst measurement is used. A combination of both measurements can be used to detect and quantify the presence of injection water of a different salinity from that of the connate water.

The master calibration of the RST and RSTPro tools is conducted annually to eliminate tool-to-tool variation. The tool is positioned within a polypropylene sleeve in a horizontally positioned calibration tank filled with chlorides-free water.

Calibration

The sigma, WFL\* water flow log, and PVL\* phase velocity log modes of the RST and RSTPro detectors do not require calibration. The gamma ray detector does not require calibration either.

#### Specifications

Measurement Specificat	ions
	RST and RSTPro Tools
Output	Inelastic and capture yields of various elements, carbon/oxygen ratio, formation capture cross section (sigma), porosity, borehole holdup, water velocity, phase velocity, SpectroLith* processing
Logging speed <sup>1</sup>	Inelastic mode: 100 ft/h [30 m/h] (formation dependent) Capture mode: 600 ft/h [183 m/h] (formation and salinity dependent) RST sigma mode: 1,800 ft/h [549 m/h] RSTPro sigma mode: 2,800 ft/h [850 m/h]
Range of measurement	Porosity: 0 to 60 V/V
Vertical resolution	15 in [38.10 cm]
Accuracy	Based on hydrogen index of formation
Depth of investigation <sup>2</sup>	Sigma mode: 10 to 16 in [20.5 to 40.6 cm] Inelastic capture (IC) mode: 4 to 6 in [10.2 to 15.2 cm]
Mud type or weight limitations	None
Combinability	RST tool: Combinable with the PL Flagship* system and CPLT* combinable production logging tool RSTPro tool: Combinable with tools that use the PS Platform* telemetry system and Platform Basic Measurement Sonde (PBMS)

See Tool Planner application for advice on logging speed.
\*Depth of investigation is formation and environment dependent.

	RST-A and RST-C	RST-B and RST-D
Temperature rating	302 degF [150 degC] With flask: 400 degF [204 degC]	302 degF [150 degC]
Pressure rating	15,000 psi [103 MPa] With flask: 20,000 psi [138 MPa]	15,000 psi [103 MPa]
Borehole size—min.	114/s in [4.60 cm] With flask: 2/4 in [5.72 cm]	2% in [7.30 cm]
Borehole size—max.	9% in [24.45 cm] With flask: 9% in [24.45 cm]	9% in [24.45 cm]
Outside diameter	1.71 in [4.34 cm] With flask: 2.875 in [7.30 cm]	2.51 in [6.37 cm]
Length	23.0 ft [7.01 m] With flask: 33.6 ft [10.25 m]	22.2 ft [6.76 m]
Weight	101 lbm [46 kg] With flask: 243 lbm [110 kg]	208 lbm [94 kg]
Tension	10,000 lbf [44,480 N] With flask: 25,000 lbf [111,250 N]	10,000 lbf [44,480 N]
Compression	1,000 lbf [4,450 N] With flask: 1,800 lbf [8,010 N]	1,000 lbf [4,450 N]

#### Tool quality control

#### Standard curves

The RST and RSTPro standard curves are listed in Table 1.

	TPro Standard Curves
Output Mnemonic	Output Name
BADL_DIAG	Bad level diagnostic
CCRA	RST near/far instantaneous count rate
COR	Carbon/coygen ratio
CRRA	Near/far count rate ratio
CRRR	Count rate regulation ratio
DSIG	RST sigma difference
FBAC	Multichannel Scaler (MCS) far background
FBEF	Far beam effective current
FCOR	Far carbon/oxygen ratio
FEGF	Far capture gain correction factor
FEOF	Far capture offset correction factor
FERD	Far capture resolution degradation factor (RDF)
FIGF	Far inelastic gain correction
FIOF	Far inelastic offset correction factor
FIRD	Far inelastic RDF
IC	Inelastic capture
IRAT_FIL	RST near/far inelastic ratio
NBEF	Near beam effective current
NCOR	Near carbon/oxygen ratio
NEGF	Near capture gain correction factor
NEOF	Near capture offset correction factor
NERD	Near capture RDF
NIGF	Near inelastic gain correction
NIOF	Near inelastic offset correction factor
NIRD	Near inelastic RDF
RSCF_RST	RST selected far count rate
RSCN_RST	RST selected near count rate
SBNA	Sigma borehole near apparent
SFFA_FIL	Sigma formation far apparent
SFNA_FIL	Sigma formation near apparent
SIGM	Formation sigma
SIGM SIG	Formation sigma uncertainty
TRAT FIL	RST near/far capture ratio

#### Operation

The RST and RSTPro tools should be run eccentered. The main inelastic capture characterization database does not support a centered tool, thus it is important to ensure that the tool is run eccentered. However, for a WFL water flow log, a centered tool is recommended to better evaluate the entire wellbore region.

#### **Formats**

The format in Fig. 1 is used mainly as a hardware quality control.

#### · Depth track

- Deflection of the BADL\_DIAG curve by 1 unit indicates that frame data are being repeated (resulting from fast logging speed or stalled data). A deflection by 2 units indicates bad spectral data (too-low count rate).

#### Track 1

- CRRA, CRRR, NBEF, and FBEF are shown; FBEF should track openhole porosity when properly scaled.

- The IC mode gain correction factors measure the distortion of the energy inelastic and elastic spectrum in the near and far detectors relative to laboratory standards. They should read between 0.98 and 1.02.

#### Track 7

- The IC mode offset correction factors are described in terms of gain, offset, and resolution degradation of the inelastic and elastic spectrum in the near and far detectors. They should read between -2 and 2.

#### · Track 8

- Distortion on these curves affects inelastic and capture spectra from the near and far detectors. They should be between 0 and 15. Anything above 15 indicates a tool problem or a tool that is too hot (above 302 degF [150 degC]), which affects yield processing.

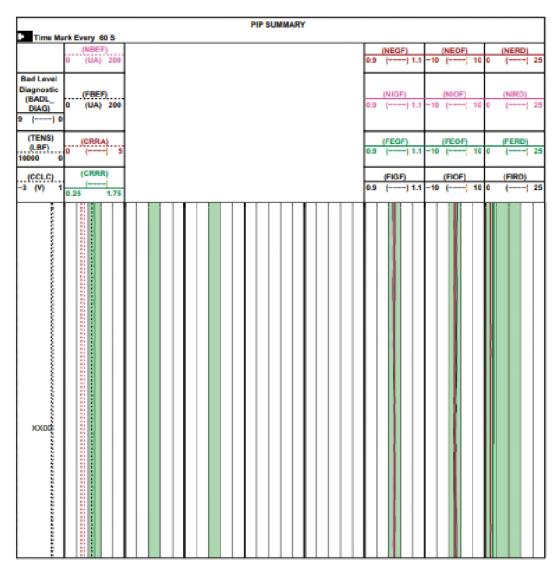


Figure 1. RST and RSTPro hardware format.

The format in Fig. 2 is used mainly for sigma quality control.

#### · Depth track

- Deflection of the BADL\_DIAG curve by 1 unit indicates that frame data are being repeated (resulting from fast logging speed or stalled data). A deflection by 2 units indicates bad spectral data (too-low count rate).

#### · Tracks 2 and 3

- The IRAT\_FIL inelastic ratio increases in gas and decreases with porosity.
- DSIG in a characterized completion should equal approximately zero. Departures from zero indicate either the environmental parameters are set incorrectly or environment is different from the characterization database (e.g., casing is not fully centered in the wellbore or the tool is not eccentered). Shales typically read 1 to 4 units from the baseline of zero because they are not characterized in the database.

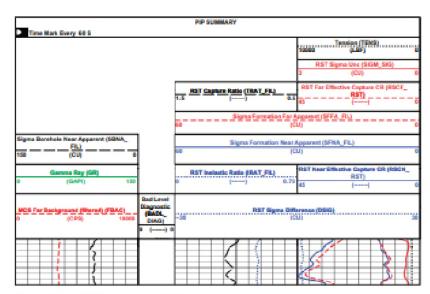


Figure 2. RST and RSTPro sigma standard format.

#### Response in known conditions

In front of a clean water zone, COR is smaller than the value logged across an oil zone. Oil in the borehole affects both the near and far COR, causing them to read higher than in a water-filled borehole. In front of shale, high COR is associated with organic content.

The computed yields indicate contributions from the materials being measured (Table 2).

Table 2. Contribut	ing Materials to RST and RSTPro Yields
Element	Contributing Material
C and O	Matrix, borehole fluid, formation fluid
Si	Sandstone matrix, shale, cement behind casing
Ca	Carbonates, cement
Fe	Casing, tool housing

Bad cement quality affects readings (Table 3). A water-filled gap in the cement behind the casing appears as water to the IC measurement. Conversely, an oil-filled gap behind the casing appears as oil to the IC measurement.

Table 3. RST and RS	TPro Capture and Sigma Modes
Medium	Sigma, cu
Oil	18 to 22
Gas	0 to 12
Water, fresh	20 to 22
Water, saline	22 to 120
Matrix	8 to 12
Shale	35 to 55

### **Schl**umberger

### Cement Bond Tool

#### Overview

The cement bond log (CBL) made with the Cement Bond Tool (CBT) provides continuous measurement of the attenuation of sound pulses, independent of casing fluid and transducer sensitivity. The tool is self-calibrating and less sensitive to eccentering and sonde tilt than the traditional single-spacing CBL tools. The CBT additionally gives the attenuation of sound pulses from a receiver spaced 0.8 ft [0.24 m] from the transmitter, which is used to aid interpretation in fast formations.

A CBL curve computed from the three attenuations available enables comparison with CBLs based on the typical 3-ft [0.91-m] spacing. This computed CBL continuously discriminates between the three attenuations to choose the one best suited to the well conditions. An interval transit-time curve for the casing is also recorded for interpretation and quality control.

A Variable Density\* log (VDL) is recorded simultaneously from a receiver spaced 5 ft [1.52 m] from the transmitter. This display provides information on the cement/formation bond and other factors that are important to the interpretation of cement quality.

#### **Specifications**

Measurement Specifications	
Output	Attenuation measurement, CBL, VDL image, transit times
Logging speed	1,800 ft/h [549 m/h] <sup>†</sup>
Range of measurement	Formation and casing dependent
Vertical resolution	CBL: 3 ft [0.91 m] VDL: 5 ft [1.52 m] Cement map: 2 ft [0.61 m]
Accuracy	Formation and casing dependent
Depth of investigation	CBL: casing and cement interface VDL: depends on bonding and formation
Mud type or weight limitations	None
<sup>1</sup> Speed can be reduced depending on data ou	ality.

System can be resource depending on base querily.

Measurement Specifications		
Temperature rating	350 degF [177 degC]	
Pressure rating	20,000 psi [138 MPa]	
Borehole size—min.	3.375 in [8.57cm]	
Borehole size-max.	13.375 in [33.97 cm]	
Outside diameter	2.75 in [6.985 cm]	
Weight	309 lbm [140 kg]	

#### Calibration

Sonde normalization of sonic cement bond tools is performed with every Q-check. Q-check frequency is also dependent on the number of jobs run, exposure to high temperature, and other factors.

The sonic checkout setup used for calibration is supported with two stands, one on each end. A stand in the center of the tube would distort the waveform and cause errors. One end of the tube is elevated to assist in removing all air in the system, and the tool is positioned in the tube with centralizer rings.

#### **Tool quality control**

#### Standard curves

CBT standard curves are listed in Table 1.

Output Mnemonic	Output Name
CCL	Casing collar locator amplitude
DATN	Discriminated BHC attenuation
DBI	Discriminated bond index
DCBL	Discriminated synthetic CBL
DT	Interval transit time of casing (delta-t)
DTMD	Delta-t mud (mud slowness)
GR	Gamma ray
NATN	Near 2.4-ft attenuation
NBI	Near bond index
NCBL	Near synthetic CBL
R32R	Ratio of receiver 3 sensitivity
	to receiver 2 sensitivity, dB
SATN	Short 0.8-ft attenuation <sup>†</sup>
SB1	Short bond index <sup>1</sup>
SCBL	Short synthetic CBL <sup>†</sup>
TTI	Transit time for mode 1 (upper transmitter, receiver 3 [UT-R3])
TT2	Transit time for mode 2 (UT-R2)
TT3	Transit time for mode 3 (lower transmitter, receiver 2 [LT-R2])
TT4	Transit time for mode 4 (LT-R3)
TT6	Transit time for mode 6 (UT-R1)
ULTR	Ratio of upper transmitter output strength to the lower transmitter output strength
VDL	Variable Density log

<sup>1</sup> in last formations on

Log Quality Control Reference Manual

Cement Bond Tool

203

#### Operation

The tool should be run centralized.

A log should be made in a free-pipe zone (if available). Where a microannulus is suspected, a repeat section should be made with pressure applied to the casing.

#### Formats

The format in Fig. 1 is used both as an acquisition and quality control format.

#### Track I.

- DT and DTMD are derived from the transit-time measurements from all transmitter-receiver pairs. They respond to eccentralization of any of the six measurements modes and are a sensitive indicator of wellbore conditions. In a low-quality cement bond or free pipe, both readings are correct. In well-bonded sections, the transit time may cycle skip, affecting the DT and DTMD values.
- CCL deflects in front of casing collars.
- GR is used for correlation purposes.

#### Track 2

 DCBL is related to casing size, casing weight, and mud. As a quality control DCBL should be checked against the expected responses in known conditions (see the following section). Also, DCBL should match the VDL image readings.

#### Track 3

VDL is a map of the waveform amplitude versus depth and it should have good contrast. It provides information on the cement/formation bond, which is important for cement quality interpretation. The VDL image should be cross checked that it matches the DCBL readings. For example, in a free-pipe section, the DCBL amplitude reads high and VDL shows strong casing arrivals with no formation arrivals. In a zone of good bond for the casing to the formation, the CBL amplitude reads low and the VDL has weak casing arrivals and clear formation arrivals.

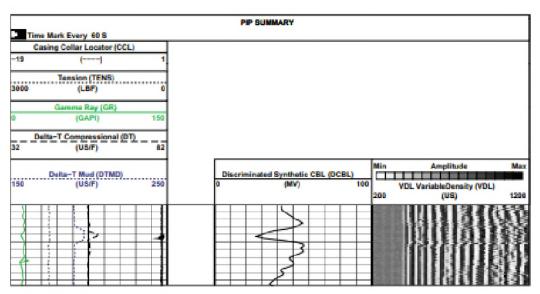


Figure 1. CBT standard format for CBL and VDL.

The format in Fig. 2 is also used both as an acquisition and quality . Track 3 control format.

#### · Track 1

- The transit time pairs should overlay (TT1C overlays TT3C, and TT2C overlays TT4C) because these pairs are derived from equivalent transmitter-receiver spacings. In very good cement sections, the transit-time curve may be affected by cycle skipping. DT and DTMD may be also affected.

#### · Track 2

- The ULTR and R32R ratios are quality indicators of the transmitter or receiver strengths. They should be 0 dB ± 3 dB, unless one of the transmitters or receivers is weak. Both curves should be checked for consistency and stability.

- DATN should equal NATN in free-pipe sections. In the presence of cement behind casing and in normal conditions, NATN reads higher than DATN.

#### Track 4

- VDL is a map of the waveform amplitude versus depth that should have good contrast. It provides information on the cement/formation bond, which is important for cement quality interpretation. The VDL image should be cross checked that it matches the DCBL readings.

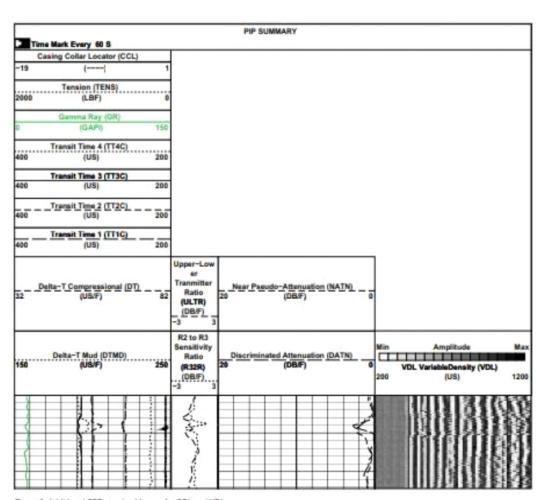


Figure 2. Additional CBT standard format for CBL and VDL

#### Response in known conditions

- . DT in casing should read the value for steel (57 us/ft ± 2 us/ft [187 us/m  $\pm$  6.6 us/m]).
- · DTMD should be compared with known velocities (water-base mud: 180-200 us/ft [590-656 us/m], oil-base mud: 210-280 us/ft [689-919 us/m]).
- · Typical responses for different casing sizes and weights are listed in Table 2.

Table 2. Typical CBT Response in Known Conditions					
Casing Size, in	Casing Weight, lbm/ft	DCBL in Free Pipe, mV	TT1, us	TT2, us	TT5, us
4.5	11.6	84 ± 8	252	195	104
5	13	77 ± 7	259	203	112
5.5	17	71 ± 7	267	210	120
7	24	61 ± 6	290	233	140
8.625	38	55 ± 6	314	257	166
9.625	40 <sup>†</sup>	52 ± 5	329	272	NM <sup>E</sup>

<sup>\*</sup>Although the CBT operates in up to 1396 in casing, the VDL presentation mainly shows casing arrivals where casings of 996 in and larger are logged.

<sup>1</sup>NM = not meaningful

## Schlumberger

# Cement Bond Logging

#### Overview

Cement bond tools measure the bond between the casing and the cement placed in the annulus between the casing and the wellbore. The measurement is made by using acoustic sonic and ultrasonic tools. In the case of sonic tools, the measurement is usually displayed on a cement bond log (CBL) in millivolt units, decibel attenuation, or both. Reduction of the reading in millivolts or increase of the decibel attenuation is an indication of better-quality bonding of the cement behind the casing to the casing wall. Factors that affect the quality of the cement bonding are

- · cement job design and execution as well as effective mud removal
- · compressive strength of the cement in place
- · temperature and pressure changes applied to the casing after cementing
- · epoxy resin applied to the outer wall of the casing.

The recorded CBL provides a continuous measurement of the amplitude of sound pulses produced by a transmitter-receiver pair spaced 3-ft [0.91-m] apart. This amplitude is at a maximum in uncemented free pipe and minimized in well-cemented casing. A transit-time (TT) curve of the waveform first arrival is also recorded for interpretation and quality control.

A Variable Density\* log (VDL) is recorded simultaneously from a receiver spaced 5 ft [1.52 m] from the transmitter. The VDL display provides information on the cement quality and cement/formation bond.

#### **Specifications**

Measurement Specifications			
, i	Digital Sonic Logging Tool (DSLT) and Hostile Environment Sonic Logging Tool (HSLT) with Borehole-Compensated (BHC)	Slim Array Sonic Tool (SSLT) and SlimXtreme* Sonic Logging Tool (QSLT)	
Dutput	SLS-C, SLS-D, SLS-W, and SLS-E. <sup>‡</sup> 3-ft [0.91-m] CBL Variable Density waveforms	3-ft [0.91-m] CBL and attenuation 1-ft [0.30-m] attenuation 5-ft [1.52-m] Variable Density waveforms	
ogging speed 3,600 ft/h [1,097 m/h]		3,600 ft/h [1,097 m/h]	
Range of measurement	40 to 200 us/ft [131 to 656 us/m]	40 to 400 us/ft [131 to 1,312 us/m]	
/ertical resolution Amplitude (mV): 3 ft [0.91 m] VDL: 5 ft [1.52 m]		Near attenuation: 1 ft [0.30 m] Amplitude (mV): 3 ft [0.91 m] VDL: 5 ft [1.52 m]	
Depth of investigation Synthetic CBL from discriminated attenuation (DCBL): Casing and cement interface VDL: Depends on cement bonding and formation properties		DCBL: Casing and cement interface VDL: Depends on cement bonding and formation properties	
Mud type or weight limitations	None	None	
Special applications		Conveyed on wireline, drillpipe, or coiled tubing Logging through drillpipe and tubing, in small casings, fast formations	
		The same of the sa	

<sup>\*</sup>The DSLT uses the Sonic Logging Seeds (SLS) to measure coment band amplitude and VDL exaluation

	DSLT	HSLT	SSLT	QSLT
Temperature rating	302 degF [150 degC]	500 degF [260 degC]	302 degF [150 degC]	500 degF [260 degC]
Pressure rating	20,000 psi [138 MPa]	25,000 psi [172 MPa]	14,000 psi [97 MPa]	30,000 psi [207 MPa]
Casing ID-min.	5 in [12.70 cm]	5 in [12.70 cm]	3)6 in [8.89 cm]	4 in [10.16 cm]
Casing ID-max.	18 in [45.72 cm]	18 in [45.72 cm]	8 in [20.32 cm]	8 in [20.32 cm]
Outside diameter	3% in [9.21 cm]	394 in [9.53 cm]	2½ in [6.35 cm]	3 in [7.62 cm]
Length	SLS-C and SLS-D: 18.7 ft [5.71 m] SLS-E and SLS-W: 20.6 ft [6.23 m]	With HSLS-W sonde: 25.5 ft [7.77 m]	23.1 ft [7.04 m] With inline centralizers: 29.6 ft [9.02 m]	23 ft [7.01 m] With inline centralizers 29.9 ft [9.11 m]
Weight	SLS-C and SLS-D: 273 lbm [124 kg] SLS-E and SLS-W: 313 lbm [142 kg]	With HSLS-W sonde: 440 lbm [199 kg]	232 lbm [105 kg] With inline centralizers: 300 lbm [136 kg]	295 lbm [134 kg] With inline centralizers 407 lbm [185 kg]
Tension	29,700 lbf [132,110 N]	29,700 lbf [132,110 N]	13,000 IM [57,830 N]	13,000 lbf [57,830 N]
Compression	SLS-C and SLS-D: 1,700 lbf [7,560 N] SLS-E and SLS-W: 2,870 lbf [12,770 N]	With HSLS-W sonde: 2,870 lbf [12,770 N]	4,400 lbf [19,570 N]	4,400 lbf (19,570 N)

#### Calibration

Sonde normalization of sonic cement bond tools is performed with every Q-check. Scheduled frequency of Q-checks varies for each tool. Q-check frequency is also dependent on the number of jobs run, exposure to high temperature, and other factors.

The sonic checkout setup used for calibration is supported with two stands, one on each end. A stand in the center of the tube would distort the waveform and cause errors. One end of the tube is elevated to assist in removing all air in the system, and the tool is positioned in the tube with centralizer rings.

#### Tool quality control

#### Standard curves

CBL standard curves are listed in Table 1.

Output Mnemonic	Output Name	
BI	Bond index	
CBL	Cement bond log (fixed gate)	
CBLF	Fluid-compensated cement bond log	
CBSL	Cement bond log (sliding gate)	
CCL	Casing collar log	
GR	Gamma ray	
π	Transit time (fixed gate)	
TTSL	Transit time (sliding gate)	
VDL	Variable Density log	

#### Operation

The tool must be run centralized.

A log should be made in a free-pipe zone (if available). Where a microannulus is suspected, a repeat section should be made with pressure applied to the casing.

The format in Fig. 1 is used for both acquisition and quality control.

#### · Track 1

- TT and TTSL should be constant through the log interval and should overlay. These curves deflect near casing collars. In sections of very good cement, the signal amplitude is low; detection may be affected by cycle skipping. GR is used for correlation purposes, and CCL serves as a reference for future cased hole correlations...

#### Track 2

 CBL measured in millivolts from the fixed gate should be equal to CBSL measured from the sliding gate, except in cases of cycle skipping or detection on noise.

#### Track 3

- VDL is a presentation of the acoustic waveform at a receiver of a sonic measurement. The amplitude is presented in shades of a gray scale. The VDL should show good contrast. In free pipe, it should be straight lines with chevron patterns at the casing collars. In a good bond, it should be gray (low amplitudes) or show strong formation signals (wavy lines).

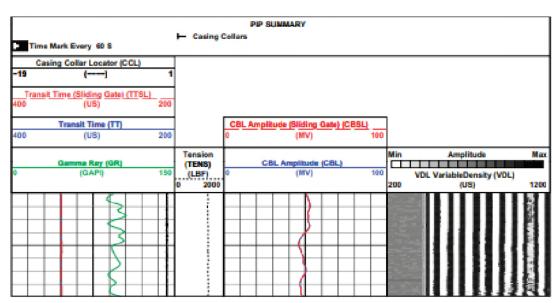


Figure 1. DSLT standard format.

### Response in known conditions

The responses in Table 2 are for clean, free casing.

Table 2. Typical CBL Response in Known Conditions						
Casing OD, in	Weight, lbm/ft	Nominal Casing ID, in	CBL Amplitude Response in Free Pipe, mV			
5	13	4.494	77 ± 8			
5.5	17	4.892	71 ± 7			
7	23	6.366	62 ± 6			
8.625	36	7.825	55 ± 6			
9.625	47	8.681	52 ± 5			
10.75	51	9.850	49 ± 5			
13.375	61	12.515	43 ± 4			
18.625	87.5	17.755	35 ± 4			